Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer, Bureau of Air Regulation

THROUGH: Syed Arif, New Source Review Section SA

FROM: Bruce Mitchell, New Source Review Section

DATE: November 13, 2008

SUBJECT: Project No. 0570039-040-AC
Tampa Electric Company
Big Bend Station
Two Simple Cycle Combustion Turbines-Generator Peaking Project

Attached for your review are the following items:

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

The P.E. certification briefly summarizes the proposed permit project. The Technical Evaluation and Preliminary Determination provide a detailed description of the project, rationale, and conclusion. I recommend your approval of the attached Draft Permit for this project.

Attachments

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

November 19, 2008

Mr. Paul L. Carpinone
Director, Environmental Health and Safety
Tampa Electric Company
Big Bend Station
P.O. Box 111
Tampa, Florida 32601-0111

Re: Project No. 0570039-040-AC
Tampa Electric Company – Big Bend Station
Two Simple Cycle Combustion Turbines-Generator Peaking Project

Dear Mr. Carpinone:

On August 22, 2008, you submitted an application requesting authorization to construct two simple cycle combustion turbines (SCCT), with one common electrical generator, and one emergency reciprocating internal combustion engine-generator set at the existing Big Bend Station. This facility is located at 13031 Wyandotte Road in Apollo Beach, Hillsborough County, Florida. Enclosed are the following documents:

- Technical Evaluation and Preliminary Determination;
- Draft Permit and Appendices;
- Written Notice of Intent to Issue Air Permit; and
- Public Notice of Intent to Issue Air Permit.

The Public Notice of Intent to Issue Air Permit is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

If you have any questions, please contact the Project Engineer, Bruce Mitchell, at 850/413-9198.

Sincerely,

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

TLV/sa/bm

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

Authorized Representative:
Mr. Paul L. Carpinone
Director, Environmental Health and Safety

Project No. 0570039-040-AC
Big Bend Station
Two Simple Cycle Combustion Turbines-Generator Peaking Project
Hillsborough County, Florida

Facility Location: Tampa Electric Company operates an existing electric utility, the Big Bend Station (Big Bend), located at 13031 Wyandotte Road in Apollo Beach, Hillsborough County, Florida.

Project: The proposed project is to construct two simple cycle combustion turbines, with one common electrical generator, and one emergency reciprocating internal combustion engine-generator set at the existing Big Bend facility. Details of the project are provided in the application and the enclosed Technical Evaluation and Preliminary Determination.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210 and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above.

Notice of Intent to Issue Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S., or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S., and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at above address or phone number. Pursuant to Rules 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of 14 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 14-day period. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue Air Permit package (including the Public Notice, the Technical Evaluation and Preliminary Determination, and the Draft Permit), was sent by electronic mail (or a link to these documents made available electronically on a publicly accessible server) with received receipt requested before the close of business on 11/19/08 to the persons listed below.

Mr. Paul L. Carpinone, Tampa Electric Company (plcarpinone@tecoenergy.com)
Mr. David M. Lukcic, Tampa Electric Company (dmlukcic@tecoenergy.com)
Mr. Byron T. Burrows, Tampa Electric Company (btburrows@tecoenergy.com)
Mr. Andrew T. Nguyen, Tampa Electric Company (atnguyen@tecoenergy.com)
Mr. Thomas W. Davis, P.E., Environmental Consulting & Technology, Inc. (tdavis@ectinc.com)
Mr. Jerry Campbell, Hillsborough County Environmental Protection Commission (campbell@epchc.org)
Ms. Diana Lee, Hillsborough County Environmental Protection Commission (Lee@epchc.org)
Mr. Roger Zhu, Hillsborough County Environmental Protection Commission (Zhu@epchc.org)
Ms. Vickie Gibson, DEP-BAR (Victoria.Gibson@dep.state.fl.us) (for read file)

Clerk Stamp

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

_________________ (Clerk) 11/19/08 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation
Project No. 0570039-040-AC
Tampa Electric Company – Big Bend Station
Hillsborough County, Florida

Applicant: The applicant for this project is the Tampa Electric Company. The applicant's authorized representative and mailing address is: Mr. Paul L. Carpinone, Director, Environmental Health and Safety, Tampa Electric Company, Post Office 111, Tampa, Florida 33601-0111.

Facility Location: Tampa Electric Company operates an existing electric utility, the Big Bend Station (Big Bend), located at 13031 Wyandotte Road in Apollo Beach, Hillsborough County, Florida.

Project: The proposed project is to construct two simple cycle combustion turbines (SCCT), with one common electrical generator, and one emergency reciprocating internal combustion engine (RICE)-generator set at the existing Big Bend facility. SCCT 4A and SCCT 4B will be coupled to one common generator having a nominal gross generation capacity of 62 megawatts (MW). For each SCCT, the applicant proposes to fire pipeline-quality natural gas (NG) and ultra low sulfur diesel fuel (ULSD) while operating in the simple cycle mode. The NG shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet and the ULSD shall contain no more than 0.0015 percent sulfur content, by weight. The hours of operation are limited to 3,500 per SCCT per year while firing NG and 500 per SCCT per year while firing ULSD (any hour used to fire ULSD fuel will decrease an hour that could have been used to fire natural gas). Excluding emergency conditions, the RICE-generator set will only be operated for approximately 2 hours per week (100 hr/yr) each for routine testing and maintenance purposes and will fire only ULSD.

The project is not subject to the rules for the Prevention of Significant Deterioration (PSD) at Rule 62-212.400, Florida Administrative Code (F.A.C.), because there will not be significant net emissions increases of any criteria pollutant. For nitrogen oxides (NOx), creditable emission decreases from the permanent shutdown of the existing combustion turbines Nos. 1, 2 and 3 were used to net out of PSD new source review requirements at Rule 62-212.400, F.A.C. Therefore, the project is considered a minor modification to a major facility. An air quality impact analysis was not required.

An oxidation catalyst will be installed on each SCCT to reduce the emissions of carbon monoxide (CO) and volatile organic compounds (VOC). The use of low sulfur fuels, essentially inherently clean fuels, will minimize the emissions of sulfur dioxide (SO_2), sulfuric acid mist (SAM), particulate matter (PM) and PM with an aerodynamic diameter equal to or less than 10 microns (PM_{10}). Water injection will be used on each SCCT to minimize the emissions of NOx.

Each SCCT will be subject to the allowable NOx and SO_2 emission limitations given in Title 40, Code of Federal Regulations, Part 60 (40 CFR 60), Subpart KKKK - Standards of Performance for Stationary Combustion Turbines that Commence Construction after February 18, 2005; however, for NOx when firing ULSD, the applicant requested a more stringent limit than what is allowed by the subpart.

The RICE-generator set is not subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR 63, Subpart ZZZZ, for Stationary RICE, because the potential emissions of hazardous air pollutants are less than major for the project; however, the RICE-generator set is entitled to the generic emissions unit exemption at Rule 62-210.300(3)(b)1., F.A.C., One or More Emergency Generators Located Within a Single Facility.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210 and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida 32301. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. In addition, electronic copies of these documents are available on the following web site:

www.dep.state.fl.us/air/eproducts/apds/default.asp.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S., or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of 14 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 14-day period. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address and telephone number of the petitioner; the name address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial rights will be affected by the agency determination; (c) A statement of when and how the petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available for this proceeding.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Tampa Electric Company

Big Bend Station
Two Simple Cycle Combustion Turbines SCCT 4A and SCCT 4B

Hillsborough County

0570039-040-AC

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

November 19, 2008

1. GENERAL PROJECT INFORMATION

- **Facility Description and Location**

Facility Description. The facility is an electricity utility, which is categorized under Standard Industrial Classification Code SIC No. 4911.

Tampa Electric Company's Big Bend Station (Big Bend) is a nominal 2,028 megawatt (MW) electric generation facility. This facility consists of the following emissions units and operations: four steam boilers (Units Nos. 1 - 4); four steam turbines; three simple-cycle combustion turbines (SCCT Nos. 1, 2, and 3); solid fuels, fly ash, limestone, gypsum, slag, and bottom ash storage and handling facilities, and fuel oil storage tanks. Units Nos. 1, 2, 3 and 4 have nominal maximum heat inputs of 4037, 3996, 4115 and 4330 million British thermal units per hour (MMBTU/hr), respectively. Units Nos. 1 through 4 are fired with coal and with petroleum coke (petcoke) in a mixture with coal up to 20.0% petcoke/80.0% coal (by weight), or a coal blended with coal residual generated from the Polk Power Station, or a coal/petcoke blend further blended with coal residual generated from the Polk Power Station. The combustion turbines are fired with No. 2 distillate fuel oil. In addition, there are unregulated emissions units, insignificant emissions units and/or activities and a ship surface coating operation.

Solid fuel is unloaded from ship/barge into the solid fuel yard, the blending bins or directly to the tripper room via belt conveyors. Solid fuel from the piles is loaded onto belt conveyors using a rail mounted or mobile reclaimer. The solid fuel is then belt conveyed to the blending bins, which consists of six storage bins, where the solid fuel may be blended for use at the plant or transloaded into trucks for shipment off site. Particulate matter (PM) emissions from the conveyors in the blending bins are controlled by 4 rotoclones, one at the conveyor drop and one for every 2 bins. Blending bins can either feed the transloader, or solid fuel can be conveyed, via 2 parallel belts (T1 and T2) to 2 crushers (each belt has a crusher) or diverted directly to the tripper room. PM emissions from the 2 crushers and transfer tower are controlled by 2 rotoclones. From the tripper room, 2 trippers bunker the solid fuels into 4 solid fuel bunkers. Each unit has its own respective bunker. From the bunkers, the solid fuel is gravity fed into 14 mills and then fed into the boilers. There are 3 ball mills, each for Unit Nos. 1 - 3, and 5 bowl mills for Unit No. 4. From the mills, the solid fuel is pneumatically fed into classifiers, two for each mill on Units Nos. 1-3 and one for each mill on Unit No. 4 for a total of 23 classifiers, and then into the respective boiler. PM emissions from Units Nos. 1-4 are controlled by individual Electrostatic Precipitators (ESP). Units Nos. 1 - 4 sulfur dioxide (SO_2) emissions are controlled by flue gas desulfurization (FGD) scrubber systems. When Units Nos. 1 - 3 burn petcoke, the exhaust gases, following particulate matter removal by the units' ESP, will be routed to the inlet of the flue gas desulfurization (FGD) system scrubber. In the integrated mode, Unit No. 3 will meet the same sulfur dioxide emissions limitations as Unit No. 4. The FGD scrubber will continue to treat the exhaust gas from Unit No. 4. The FGD scrubber outlet stream, consisting of the combined Unit No. 3 and Unit No. 4 treated exhaust, will then be split and discharged through stacks CS002 and CS003 (authorized in project No. 0570039-031-AC).

Fly ash from Units Nos. 1 and 2 is vented into Fly Ash Silo No. 1 which is controlled by a baghouse. Fly ash from Unit No. 3 is vented into Fly Ash Silo No. 2, which can also receive fly ash from Units Nos. 1 and 2. Fly ash from Unit No. 4 is vented into Fly Ash Silo No. 3. The fly ash from each silo is then loaded into trucks and transported off site, while the bottom ash from Unit No. 4 is conveyed across Big Bend Road south of Big Bend to a settling pond. Each fly ash silo is controlled by a baghouse.

The byproduct gypsum is conveyed to the east side of the plant for dewatering and transporting off site. Limestone is unloaded to an underground hopper conveyor belt system to the limestone storage building on the east side of the by-product gypsum area. From the storage building, limestone is belt conveyed into 3 storage silos and then gravity fed into the mill room. Three rotary mills grind the limestone and mix it with water to form a slurry that is stored in 3 storage tanks for use in the FGD. The slurry is then pumped to the 4 reaction tanks of Units 1- 4 scrubbers that are located directly south of and adjacent to the absorption towers of the FGD scrubber. Gypsum is sold and transported offsite and can be stored south of Big Bend Road prior to offsite removal.

There are 3 existing combustion turbines (CT) manufactured by Westinghouse. They all fire No. 2 fuel oil. CT No. 1 is near the plant and CT Nos. 2 and 3 are on the northern side of the property. There is a large No. 2 fuel oil storage tank near CT Nos. 2 and 3 and a small day tank near CT No. 1.

This facility is classified as a Major Source of Air Pollution or Title V Source because emissions at least one regulated air pollutant, such as PM, PM with an aerodynamic diameter equal to or less than 10 microns (PM_{10}), SO_2, nitrogen oxides (NOx), carbon monoxide (CO) or volatile organic compounds (VOC), exceeds 100 tons per year (TPY) pursuant to Rule 62-210.200(Definitions), Florida Administrative Code (F.A.C.). This facility is within an industry included in the list of the 28 Major Facility Categories per Rule 62-210.200(Definitions-Major Source of Air Pollution), F.A.C. The Big Bend facility is in an area that is in attainment (or designated as unclassifiable or maintenance) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS).

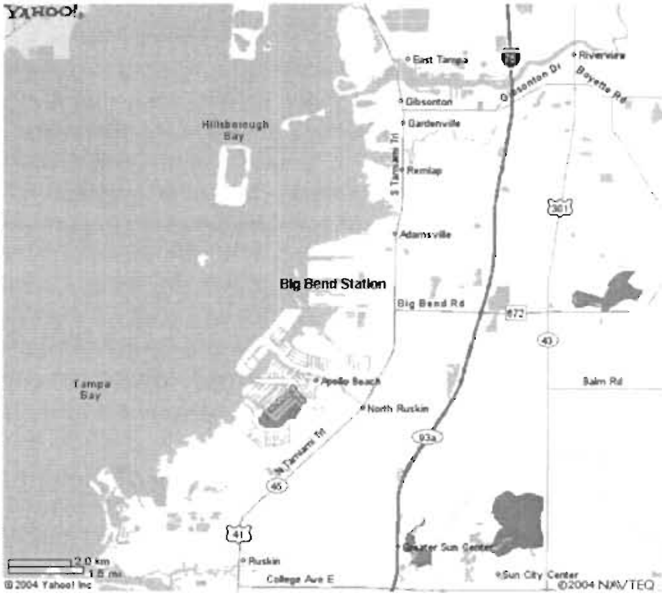
Applicant Name and Address:

Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

Authorized Representative: Paul L. Carpinone, Director, Environmental Health and Safety

Facility Location. As shown below, the Big Bend facility is located in Hillsborough County at 13031 Wyandotte Road, Apollo Beach, Florida 33572. The UTM Coordinates are Zone 17, 361.78 km East and 3075.10 km North, and the map coordinates are Latitude 27° 47' 36" and Longitude 82° 24' 11".

TAMPA, FLORIDA
CITY LOCATION OF THE FACILITY



13031 WYANDOTTE ROAD, APOLLO BEACH
FACILITY LOCATION

The following is a picture of the existing Big Bend facility.

TAMPA ELECTRIC COMPANY
BIG BEND STATION

- **Facility Regulatory Categories**

Title III: The existing facility is a major source of hazardous air pollutants (HAP).

Title IV: The existing facility has units subject to the acid rain provisions of the Clean Air Act.

Title V: The existing facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

Prevention of Significant Deterioration (PSD): The existing facility is a PSD-major source of air pollution in accordance with Rule 62-210.200(Definitions-Major Source of Air Pollution), F.A.C.

New Source Performance Standards (NSPS): SCCT 4A and 4B (Emissions Units 041 and 042, respectively) are subject to 40 Code of Federal Regulations Part 60 (40 CFR 60), Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005).

National Emission Standards for Hazardous Air Pollutants (NESHAP): SCCT 4A and 4B are not subject to 40 CFR 63, Subpart YYYY (NESHAP for Stationary Combustion Gas Turbines) because the effectiveness of the regulations were stayed by the U.S. Environmental Protection Agency (EPA) on August 18, 2004, for diffusion flame gas-fired turbines – the type of turbines proposed for this project – and the proposed project is not a major emitter of HAP.

NESHAP: The new emergency stationary reciprocating internal combustion engine (RICE) (Emissions Unit 043) is not subject to 40 CFR 63, Subpart ZZZZ [NESHAP for Stationary RICE] with a site-rating of more than 500 brake horsepower that commences construction after December 1, 2002, because the emergency RICE is not a major emitter of HAP.

- **Project Description**

The proposed project is to construct and operate two simple cycle combustion turbines (SCCT 4A and SCCT 4B) with one associated electrical generator, and one black start emergency diesel engine-generator set at the existing Big Bend facility. The project will be comprised of two SCCT coupled to a common generator having a nominal gross generation capacity of 62 MW. The emissions units will fire pipeline-quality natural gas (NG) and ultra low sulfur diesel fuel (ULSD).

ARMS ID	Proposed Emissions Unit Description
041	SCCT 4A with a common electric generator that it shares with SCCT 4B
042	SCCT 4B with a common electric generator that it shares with SCCT 4A

This project will also authorize the construction of the following emission unit that will be exempt from construction permitting requirements, but certain new source performance standards may still apply. This emissions unit will be included in the Title V Air Operating Permit.

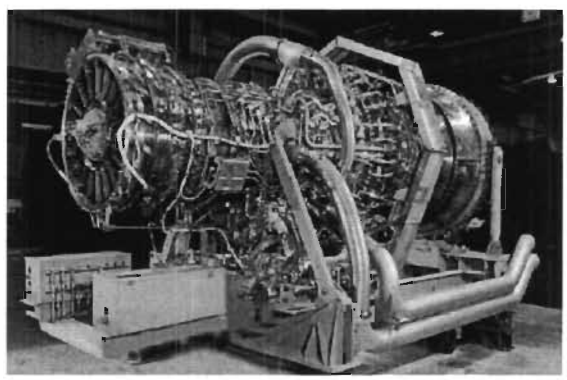
ARMS ID	Proposed Emissions Unit Description
043	One Caterpillar emergency RICE firing only ULSD entitled to a categorical exemption at Rule 62-210.300(3)(a)35.d., F.A.C.

The basis for exemption from construction permitting requirements is as follows:

> The emergency RICE will combust no more than 32,000 gallons per year of ULSD; therefore it is categorically exempt in accordance with Rule 62-210.300(3)(a)35.d., F.A.C. In addition, it is only subject to initial notification requirements under 40 CFR 63, Subpart ZZZZ.

For the new SCCT 4A and SCCT 4B, the applicant proposes to fire NG and, as a backup fuel, have the capability to fire ULSD while operating in the simple cycle mode. SCCT 4A and SCCT 4B will operate in peaking service for no more than 3,500 hours per year (hrs/yr) each, including no more than 500 hrs/yr each of ULSD firing. Any hour used to fire ULSD fuel will decrease an hour that could have been used to fire natural gas. Excluding emergency conditions, the diesel engine-generator set will only be operated for approximately 2 hours per week (100 hr/yr) for routine testing and maintenance purposes and will fire only ULSD.

Project Details. One PWPS FT8-3® SwiftPac® aeroderivative CT-generator (SwiftPac) set is intended to be installed at the existing Big Bend Station. The SwiftPac set consists of two SCCT (SCCT 4A and SCCT 4B) coupled to one common generator. Each SCCT is expected to have an approximate maximum heat input of 342.7 MMBtu/hr based upon NG firing or 302.7 MMBtu when firing ULSD [higher heating value (HHV) of the fuel, 100% load with evaporative cooling, 59° F ambient temperature, and 52° F compressor inlet air temperature]. The image below represents the approximate appearance of such a unit, with the table indication of advertised specifications.



Performance Specifications: Firing NG with Water Injection	Also available with DLN and/or inlet fogging. The SwiftPac consists of three primary units: the gas turbine unit, the generator unit, and the electric/control unit. The SwiftPac CT and generator units consist of two opposed gas turbines directly connected through a diaphragm coupled to a single double-ended electric generator.
Output (kilowatts (kW)): 61,196 Heat rate (BTU/kW-hr): 9,266 Efficiency (%): 37 Exhaust flow (lb/sec): 402 Exhaust temp (°F): 895 NOx emissions (ppmvd @ 15%O_2): 25	

- **Processing Schedule**

August 21, 2008	Received permit application
September 19, 2008	Request for Additional Information (RAI) letter issued
September 24, 2008	Received response to RAI letter; application deemed complete

2. APPLICABLE REGULATIONS

- **State Regulations**

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

Chapter	Description
62-4	Permitting Requirements
62-204	Ambient Air Quality Requirements and Federal Regulations Adopted by Reference
62-210	Permits Required, Categorical Exemptions, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms
62-212	PSD Review
62-213	Title V Air Operation Permits for Major Sources of Air Pollution
62-297	Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures

- **Federal Regulations**

This project is also subject to the applicable federal provisions regarding air quality as established by the U.S. Environmental Protection Agency (EPA) in the following sections of the Code of Federal Regulations.

40 CFR	Description
Part 60	Subpart A - General Provisions for NSPS Sources
	NSPS Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
Part 63	NESHAP Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary RICE

- **General PSD Applicability**

The Department regulates major air pollution sources in accordance with Florida's PSD program, as approved by the EPA in Florida's State Implementation Plan and defined in Rule 62-212.400, F.A.C. A PSD review is required in areas currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for a given pollutant. Pursuant to Rule 62-210.200(Definitions-Major Source of Air Pollution), F.A.C., a facility is considered "major" with respect to PSD if it emits or has the potential to emit (PTE):

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 PSD Major Facility Categories; or
- 5 tons per year of lead.

For new projects at PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the significant emissions rate and defined in Rule 62-210.200(Definitions-Significant Emissions Rate), F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant and evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" regulated pollutants.

For the pollutants of interest in this assessment, significant emissions increase is defined in Rule 62-210.200(Definitions-Significant Emissions Rate), F.A.C., as follows:

Significant Emissions Rate: With respect to any emissions increase or any ***net emissions increase****, or the potential of a facility to emit any of the following pollutants, significant emissions rate means a rate of pollutant emissions that would equal or exceed:*

a. CO: 100 tons per year (TPY);

b. NOx: 40 TPY;

c. SO_2: 40 TPY;

d. VOC: 40 TPY;

e. PM:

(i) 25 TPY of PM emissions;

(ii) 15 TPY of PM_{10} emissions.

- **PSD Applicability for the Project**

The contemporaneous creditable emissions changes are given in the following table.

Pollutant	Annual Emissions for 2 CT (TPY) [1]	Annual Emissions for Emergency Generator (TPY)	Contemporaneous Emissions Decreases from 3 CT Shutdowns [3] (TPY)	Net Change in Emissions [4] (TPY)	PSD Threshold (TPY)	PSD Applies?
NOx	121.7	0.8	-545.2	-422.7	40	**No**
CO	16.5	0.034	Not Needed (NN) [5]	16.5	100	**No**
SO_2	6.6	0.00061	NN	6.6	40	**No**
PM [2]	11.3	0.0035	NN	11.3	25	**No**
PM_{10}	11.3	0.0035	NN	11.3	15	**No**
VOC	4.7	0.0044	NN	4.7	40	**No**
Lead (Pb)	0.0006	negligible	NN	0.00062	0.6	**No**
Sulfuric Acid Mist (SAM)	0.8	negligible	NN	0.8	7	**No**

Notes: (1) Based on operation at 3,500 hr/yr/SCCT while firing only NG, or 3,000 hr/yr/SCCT while firing NG and 500 hr/yr/SCCT while firing ULSD at the highest emission rate in the simple cycle mode. Emissions are highest for CO, VOC, SO_2 and H_2SO_4 when firing only NG and for NOx, PM, PM_{10} and Pb when firing both fuels.

(2) All PM (filterable and condensible) is considered to be PM_{10} when firing both fuels.

(3) Credible emission decreases based on the shutdown of the existing CT Nos. 1, 2 and 3.

(4) Emission rates for CO, SO_2, PM, PM_{10}, VOC, Pb and SAM represent PTE for the SCCT project without consideration of netting.

(5) Contemporaneous emissions decrease not needed because the PTE for the pollutant for the proposed new construction does not exceed the significant emissions rate.

In summary, no pollutant exceeds the PSD significant emission rate, partly because of the contemporaneous emissions acquired from the committed shutdown of the existing simple cycle CT Nos. 1, 2 and 3, which will occur upon achieving commercial operation of the proposed new SCCT 4A and 4B. Pursuant to the definitions at 40 CFR 72.2, commercial operation means "to have begun to generate electricity for sale, including the sale of test generation". Therefore, a PSD preconstruction new source review and BACT determination are not required and the project is considered to be a minor modification to a major facility.

3. EMISSIONS STANDARDS

- **Brief Discussion of Emissions**

Simple Cycle Combustion Turbines (SCCT). The applicant proposes that each CT will fire NG and ULSD and operate in the simple cycle mode. The pollutants regulated under the NSPS at 40 CFR 60, Subpart KKKK, are NOx and SO_2. Other pollutant limits and restriction on hours of operation requested by the applicant for purposes of escaping PSD new source review requirements, including BACT determinations, will become State Implementation Plan (SIP) limits in the permit. Even though two SCCT are connected to a single generator, each SCCT must demonstrate compliance with the emission limits. Water injection will be used to minimize NOx emissions and an oxidation catalyst will be used to minimize CO and VOC emissions. The firing of NG and ULSD will be used to minimize visible emissions (VE) and emissions of PM/PM_{10}, and SO_2 and SAM.

NOx: When firing NG, the applicant requested the NSPS limit of 25 parts per million volume dry (ppmvd) @ 15% oxygen, 4-hour rolling average, and SIP limits of 32.0 pounds per hour (lb/hr) and 56.0 tons per year (TPY). When firing ULSD, the applicant proposed a SIP limit of 42 ppmvd @ 15% oxygen, 4-hour rolling average, which is more stringent than the NSPS limit of 74 ppmvd @ 15% oxygen for firing fuel oil (compliance with the SIP limit ensures compliance with the NSPS limit); and SIP limits of 51.3 lb/hr and 12.8 TPY. When firing both NG and ULSD, the NSPS requires compliance with the limit of NG, if the total heat input contribution of the fuels being fired is equal to or greater than 50% from NG, or ULSD, if the total heat input contribution of the fuels being fired is more than 50% from ULSD; therefore, the limits are either 25 ppmvd @ 15% oxygen, for NG, or 42 ppmvd @ 15% oxygen, for ULSD, 4-hour rolling average. These proposed emission limits will become the permit limits. Continuous compliance will be demonstrated by using a carbon dioxide (CO_2) diluent monitor and a continuous emissions monitoring system (CEMS) on each SCCT. The CEMS will also be used to comply with the Acid Rain Program provision of 40 CFR 75 for NOx.

CO: When firing NG, the applicant proposed SIP limits of 21 ppmvd @ 15% oxygen, 3-hour rolling average, 9.1 lb/hr and 8.3 TPY. When firing ULSD, the applicant proposed SIP limits of 5.1 ppmvd @ 15% oxygen, 3-hour rolling average, 2.1 lb/hr and 0.4 TPY. These proposed emission limits will become the permit limits. Continuous compliance will be demonstrated by using a carbon dioxide (CO_2) diluent monitor and a CEMS on each SCCT. In addition, CO will be used as a surrogate for VOC emissions.

VOC/HAP: The applicant indicated that the NESHAP, Subpart YYYY for a CT does not apply since the effectiveness of the regulations was stayed by the EPA on August 18, 2004, for diffusion flame gas-fired turbines – the type of turbine proposed for this project. In addition, the proposed project is also not subject to any NESHAP since the total potential HAP emissions are only 0.62 TPY. The projected potential VOC emissions are 5.1 lb/hr (2.4 TPY) for firing NG and 3.0 lb/hr (0.3 TPY) for firing ULSD. The oxidation catalyst has a projected control efficiency for VOC emissions of 50%. Because the projected emissions are very low, there will be no emissions limit imposed for VOC in the permit and CO will be used as an indicator of good combustion and a surrogate for VOC.

PM/PM_{10} and VE: Currently, there are no post-combustion PM/PM_{10} control technologies being used on combustion turbines firing NG and ULSD. The applicant recommended that the combustion of clean fuels, specifically NG and ULSD, provides the best means of PM/PM_{10} control and proposed a visible emissions limit of 10% opacity for a demonstration of good combustion and as a surrogate for PM/PM_{10} emissions. The VE standard will be imposed in the permit and be used as a surrogate for PM/PM_{10} emissions.

SO_2/SAM: The applicant indicates that fuel quality is the only technically feasible method of controlling SO_2 and SAM emissions. The applicant proposes to fire NG (2 gr/100 scf) and ULSD (0.0015% sulfur content, by weight) and show compliance by demonstrating that the potential sulfur emissions of the fuel fired in the turbine shall not exceed the NSPS limit of 0.060 lb SO_2/MMBtu heat input, 3-hour rolling average. If the applicant elects to comply with the NSPS limit based on gross output, then the standard is 0.90 lb/MWh/SCCT gross output. The applicant will monitor SO_2 emissions per 40 CFR 75, Appendix D procedures using fuel sulfur content and fuel flow rates.

Emergency RICE-Generator Set. The applicant proposed to install one emergency RICE-generator set. Excluding emergency conditions, the RICE-generator set will only be operated for approximately 2 hours per week (100 hr/yr) each for routine testing and maintenance purposes and will fire only ULSD. Under this scenario, the projected collective total ULSD usage is 5,720 gallons per year (gal/yr) and entitles it to a categorical exemption at Rule 62-210.300(3)(a)35.d., F.A.C., One or More Emergency Generators Located Within a Single Facility, because it will burn only one fuel type and fire no more than 32,000 gal/yr.

4. AIR QUALITY ANALYSIS

- **Air Quality Analysis**

Because the proposed project is not subject to preconstruction review requirements, an air quality analysis is not required.

5. CONCLUSION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. No air quality modeling analysis is required because the project does not result in a significant increase in emissions. Bruce Mitchell is the project engineer responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

DRAFT PERMIT

PERMITTEE:

Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

Authorized Representative:
Mr. Paul L. Carpinone, Director, Environmental Health and Safety

Project No. 0570039-040-AC
Big Bend Station
Two Simple Cycle Combustion Turbines-Generator Peaker Project
SIC No. 4911
Permit Expires December 31, 2010

PROJECT AND LOCATION

This permit authorizes the construction of two simple cycle combustion turbines (SCCT) with one associated electrical generator at the existing Big Bend Station. SCCT 4A and SCCT 4B will be coupled to one common generator having a nominal gross generation capacity of 62 megawatts (MW). Each SCCT will fire pipeline-quality natural gas and ultra low sulfur diesel fuel (ULSD). Each combustion turbine will operate only in the simple cycle mode. The existing facility is located at 13031 Wyandotte Road in Apollo Beach, Hillsborough County. The map coordinates are UTM Zone 17, 361.78 km East and 3075.10 km North.

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

CONTENTS

Joseph Kahn, Director
Division of Air Resource Management

Effective Date

FACILITY DESCRIPTION

The Tampa Electric Company's Big Bend Station (Big Bend) is a nominal 2,028 MW existing electrical utility plant located in Apollo Beach, Florida. The facility produces electricity for distribution to the grid as a saleable product.

The regulated emissions units at Big Bend include the following: four steam boilers (Units Nos. 1 - 4); four steam turbines; three simple-cycle combustion turbines (SCCT Nos. 1 - 3); solid fuels, fly ash, limestone, gypsum, slag, and bottom ash storage and handling facilities, and fuel oil storage tanks. Units Nos. 1, 2, 3, and 4 have nominal maximum heat inputs of 4037, 3996, 4115 and 4330 million British thermal units (MMBtu) per hour, respectively. Units Nos. 1 - 4 are fired with coal and with petroleum coke (petcoke) in a mixture with coal up to 20.0% petcoke/ 80.0% coal (by weight), or a coal blended with coal residual generated from the Polk Power Station, or a coal/petcoke blend further blended with coal residual generated from the Polk Power Station. The SCCT are fired with No. 2 distillate fuel oil. In addition, there is a ship surface coating operation. The facility has emissions units that are Acid Rain Units and regulated under the Florida Electrical Power Plant Siting Act.

PROJECT DESCRIPTION

The project will consist of constructing one Pratt & Whitney Power Systems (PWPS) FT8-3® SwiftPac® aeroderivative CT-generator unit. It will be designated as SCCT 4A & SCCT 4B. SCCT 4A and SCCT 4B will be coupled to one common generator having a nominal gross generation capacity of 62 MW. Each SCCT will only operate in the peaking service mode for no more than 3,500 hours per year (hr/yr). Each SCCT will be fired with pipeline-quality natural gas (NG) and ultra low sulfur diesel fuel (ULSD). The NG shall contain no more than 2.0 grains of total sulfur per one hundred standard cubic feet (gr S/100 scf) and the ULSD shall contain a maximum sulfur content of 0.0015 percent (%), by weight. Each SCCT will utilize water injection to reduce the emissions of NOx and an oxidation catalyst to reduce the emissions of carbon monoxide (CO) and volatile organic compounds (VOC).

The project will also include the installation of one new Caterpillar 800 kilowatt (kW) emergency stationary reciprocating internal combustion engine (RICE)-generator set. Excluding emergency conditions, the new stationary RICE-generator set will be allowed to operate for approximately two hours per week (100 hr/yr) for routine testing and maintenance purposes. The new emergency stationary RICE will be fired with ULSD. Under this proposal, the projected maximum total ULSD fuel oil usage is 5,720 gallons per year (gal/yr) and entitles it to a categorical exemption in Rule 62-210.300(3)(a)35.d., F.A.C., One or More Emergency Generators Located Within a Single Facility, because it will burn only one fuel type and fire no more than 32,000 gal/yr.

NEW EMISSION UNITS

This permit authorizes construction and installation of the following new regulated emission units:

ARMS ID	Emission Unit (EU) Description
041	SCCT 4A with a common electric generator that it shares with SCCT 4B
042	SCCT 4B with a common electric generator that it shares with SCCT 4A

This permit also authorizes construction and installation of the following emissions unit that is exempt from construction permitting requirements, but certain new source performance standards may still apply. The emissions unit will be included in the Title V Air Operating Permit.

ARMS ID	EU Description
043	One Caterpillar 800 kW emergency RICE-generator set, which is a categorically exempt emissions unit in Rule 62-210.300(3)(a)35.d., F.A.C.

REGULATORY CLASSIFICATION

Title III: The facility is a major source of hazardous air pollutants (HAP).

Title IV: The facility has units subject to the Acid Rain provisions of the Clean Air Act. The new SCCT 4A and SCCT 4B will be subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "Major Source of Air Pollution" in accordance with Rule 62-210.200(Definitions) and Chapter 62-213, F.A.C.

PSD: The facility is a PSD-major facility pursuant to Chapter 62-212, F.A.C.

New Source Performance Standards (NSPS): SCCT 4A and SCCT 4B (Emissions Units 041 and 042, respectively) are subject to 40 CFR 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005).

National Emissions Standards for Hazardous Air Pollutants (NESHAP): SCCT 4A and SCCT 4B are not subject to 40 CFR 63, Subpart YYYY (NESHAP for Stationary Combustion Gas Turbines) because the effectiveness of the regulations were stayed by the U.S. Environmental Protection Agency (EPA) on August 18, 2004, for diffusion flame gas-fired turbines – the type of turbines proposed for this project.

NESHAP: The caterpillar emergency RICE-generator set (Emissions Unit 043) is subject to 40 CFR 63, Subpart ZZZZ (NESHAP for New Stationary RICE) with a site-rating of more than 500 brake horsepower that commences construction after December 1, 2002. However, new stationary RICE that operate exclusively as emergency units are subject only to initial notification requirements.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A.	Citation Formats and Glossary of Common Terms
Appendix B.	General Conditions
Appendix C.	Common Conditions
Appendix D.	Standard Testing Requirements
Appendix E.	Standard Continuous Monitoring Requirements

Appendix F. NSPS Subpart A, General Provisions

Appendix G. NSPS Subpart KKKK, Requirements for Stationary Combustion Turbines

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action: the permit application and additional information received to make it complete; the draft permit package including the Department's Technical Evaluation and Preliminary Determination; publication and comments; and the Department's Final Determination.

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

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Hillsborough County Environmental Protection Commission (HCEPC) office. The mailing address of the HCEPC's Air Quality Division (AQD) is 3629 Queen Palm Drive, Tampa, Florida 33619. The AQD's telephone number is 813/627-2600 and facsimile number is 813/627-2660.

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

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S., and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296 and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C., and follow the application procedures in Chapter 62-4, F.A.C. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

5. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid if construction is not completed within a reasonable time. The Department may extend the expiration date upon a satisfactory showing that an extension is justified. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1) and 62-212.400(12), F.A.C.]

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

7. Source Obligation:

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

   b. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   [Rule 62-212.400(12), F.A.C.]

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

9. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. This permit does not specify the Acid Rain program requirements. These will be included in the Title V Air Operation Permit. [40 CFR 70; 40 CFR 72; and Chapter 62-213, F.A.C.]

10. Title V Air Operation Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V Air Operation Permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V Air Operation Permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050 and 62-4.220, and Chapter 62-213, F.A.C.]

The specific conditions of this subsection apply to the following emission units after construction is complete.

ARMS ID	Emission Unit Description
041	SCCT 4A with a common electric generator that it shares with SCCT 4B
042	SCCT 4B with a common electric generator that it shares with SCCT 4A

APPLICABLE STANDARDS AND REGULATIONS

1. Emissions Unit Shutdowns for PSD Preconstruction Review Purposes: Upon achieving commercial operation of SCCT 4A and SCCT 4B, existing CT Nos. 1, 2 and 3 shall be shutdown for purposes of PSD preconstruction new source review and credible emissions usage. Pursuant to the definitions at 40 CFR 72.2, commercial operation means "to have begun to generate electricity for sale, including the sale of test generation". The Department and the Compliance Authority shall be sent notification in writing of the shutdown date of each emissions unit for documenting in the data base of the air resource management system (ARMS). [Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.]

2. NSPS Requirements: Each SCCT shall comply with the applicable NSPS in 40 CFR 60 including: Subpart A (General Provisions) and Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005). See Appendix F for the NSPS Subpart A provisions and Appendix G for the NSPS Subpart KKKK provisions. Some separate reporting and monitoring may be required by the individual subparts. [Rule 62-204.800(7)(b), F.A.C.; and 40 CFR 60, Subparts A and KKKK]

EQUIPMENT DESCRIPTION

3. SCCT 4A and SCCT 4B: The permittee is authorized to install, operate and maintain one PWPS FT8-3® SwiftPac® aeroderivative CT-generator peaking unit. SCCT 4A and SCCT 4B will be coupled to one common generator having a nominal gross generation capacity of 62 MW. Each SCCT will be equipped with water injection to minimize NOx emissions and an oxidation catalyst to minimize CO and VOC emissions. Each SCCT will only be operated in the simple cycle mode. Each SCCT will be allowed to fire pipeline-quality natural gas (NG) and ultra low sulfur diesel fuel (ULSD). [Application; and Rules 62-210.200[Definitions-Potential to Emit (PTE)] and 62-4.070(3), F.A.C.]

CONTROL TECHNOLOGY

4. Wet Injection: The permittee shall install, adjust, operate, and maintain a water injection system to reduce NOx emissions from each SCCT. Prior to the initial emissions performance tests, the water injection system shall be adjusted to achieve the permitted NOx emissions standards. Thereafter, the water injection system shall be maintained and adjusted in accordance with the manufacturer's recommendations or determined best practices to minimize emissions. [Applicant request and Rule 62-4.070(3), F.A.C.]

5. Oxidation Catalyst: The permittee shall install, operate, and maintain an oxidation catalyst system to reduce CO and VOC emissions from each SCCT. The system shall be maintained and operated in accordance with the manufacturer's recommendations or determined best practices to minimize emissions. [Applicant request and Rule 62-4.070(3), F.A.C.]

PERFORMANCE REQUIREMENTS

6. Hours of Operation: SCCT 4A and SCCT 4B are allowed to operate in the peaking service mode for no more than 3,500 hr/calendar year each, including no more than 500 hr/calendar year each on ULSD. Any hour used to fire ULSD will decrease an hour that could have been used to fire NG. [Applicant request; and Rules 62-4.070(3), 62-210.200(Definitions-PTE) and 62-212.400(PSD), F.A.C.]

7. Permitted Capacity: The maximum heat input rate of each SCCT is 342.7 MMBtu per hour when firing NG or 302.7 MMBtu when firing ULSD [based on 100% load with evaporative cooling, 59° F ambient temperature, 52° F compressor inlet air temperature, and the higher heating value (HHV) of the fuel]. Heat input rates will vary depending upon turbine characteristics, ambient conditions and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Application and design; and Rules 62-4.070(3) and 62-210.200(Definitions-PTE), F.A.C.]

8. Authorized Fuels: Each CT is allowed to fire NG and ULSD. The NG shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet (2.0 gr S/100 scf). The ULSD shall contain a maximum sulfur content of 0.0015 %, by weight. [Rules 62-210.200(Definitions-PTE) and 62-212.400(PSD), F.A.C.]

9. Simple Cycle Mode: Each CT shall operate only in the simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and emission standards specified in this permit. For any request to convert these units to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel or quantity related to combined cycle conversion that may cause an increase in short or long-term emissions, the permittee shall submit a full PSD permit application complete with a proposed best available control technology (BACT) determination as if the SCCT peaking units had never been built. [Rules 62-210.200(Definitions-PTE) and 62-212.400(PSD), F.A.C.]

EMISSIONS AND TESTING REQUIREMENTS

10. Emission Standards: Emissions from each SCCT shall not exceed the following NSPS and State Implementation Plan (SIP) standards.

Pollutant	Fuel	Emission Standard[e]	Averaging Time	Compliance Method	Basis
NOx[a]	NG	25.0 ppmvd @ 15% oxygen (O_2) (NSPS)[f]	4-hr rolling avg[g]	CEMS	40 CFR 60.4320
		32.0 lb/hr/SCCT (SIP)	3 run avg.	Stack Test	Applicant requested Rule 62-4.070(3), F.A.C.
	ULSD	42.0 ppmvd @ 15% oxygen (O_2) (SIP)	4-hr rolling avg	CEMS	Applicant requested Rule 62-4.070(3), F.A.C.
		51.3 lb/hr/SCCT (SIP)	3 run avg.	Stack Test	
	NG and ULSD	25.0 ppmvd @ 15% oxygen (O_2) (NSPS)[f] or 42.0 ppmvd @ 15% oxygen (O_2) (SIP)	4-hr rolling avg[g]	CEMS	40 CFR 60.4325
CO[b]	NG	21.0 ppmvd @ 15% O_2 (SIP)	3-hr rolling avg	CEMS	Applicant requested Rule 62-4.070(3), F.A.C.
		9.1 lb/hr/SCCT (SIP)	3 run avg.	Stack Test	
	ULSD	5.1 ppmvd @ 15% O_2 (SIP)	3-hr rolling avg	CEMS	Applicant requested Rule 62-4.070(3), F.A.C.
		2.1 lb/hr/SCCT (SIP)	3 run avg.	Stack Test	
Visible Emissions[c]		10 % Opacity (SIP)	6-minute block	Visible Emissions Test	Applicant requested Rule 62-4.070(3), F.A.C.
PM[c]		NG: 2.0 gr S/100 scf (SIP) ULSD: 0.0015% S content, by wt (SIP)	N/A	Recordkeeping	Vendor data of analyses
SO_2[d]	NG	NG: 2.0 gr S/100 scf (SIP) 0.90 lb/MWh/SCCT gross output[d] (NSPS) or 0.060 lb/MMBtu/SCCT heat input[d] (NSPS)	N/A	Demonstration of fuel combusted and vendor data of analyses	Applicant requested 40 CFR 60.4330(a)(1) 40 CFR 60.4330(a)(2)
	ULSD	ULSD: 0.0015% S content, by wt (SIP) 0.90 lb/MWh/SCCT gross output[d] (NSPS) or 0.060 lb/MMBtu/SCCT heat input[d] (NSPS)			Applicant requested 40 CFR 60.4330(a)(1) 40 CFR 60.4330(a)(2)

a. The permittee shall conduct initial and annual tests [Relative Accuracy Test Audit (RATA)] on each SCCT to demonstrate compliance with the short-term NOx emission limits [ppmvd @ 15% O_2 and lb/hr (mass emissions)] per fuel type. Thereafter, continuous compliance shall be demonstrated with the 4-hour rolling average NOx emission limits by data collected from the required continuous emissions monitoring system (CEMS). When firing ULSD, compliance with the SIP limit ensures compliance with the NSPS limit of 74 ppmvd @ 15% O_2. When firing both NG and ULSD, compliance with the NSPS limit is ensured by complying with either the NSPS limit, for NG, or the SIP limit, for ULSD, depending on the contribution of the fuels of the total heat input: if the total heat input contribution is equal to or greater than 50 percent from NG, you must meet the corresponding limit for a NG-fired turbine when you are burning that fuel; similarly, when your total heat input contribution is greater than 50 percent from ULSD, you must meet the corresponding limit for ULSD for the duration of the time that you burn that particular fuel.

b. The permittee shall conduct an initial test on each SCCT to demonstrate compliance with the short-term [ppmvd @ 15% O_2 and lb/hr (mass emissions)] CO emission limits per fuel type. Thereafter, continuous compliance shall be demonstrated with the 3-hour rolling average CO emission limits by data collected by the required CEMS. CO will be used as a surrogate for VOC emissions as a demonstration of good combustion.

c. The sulfur fuel specification combined with the efficient combustion design and operation of the turbines should minimize PM emissions (PM emissions are a surrogate for PM_{10} emissions) as well as visible emissions. No stack tests are required. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: Maximum expected PM/PM_{10} emissions from each turbine are approximately 2.5 and 7.5 lb/hr for NG and ULSD, respectively.}*

d. The fuel sulfur specifications effectively limit the potential emissions of SO_2 (and essentially sulfuric acid mist). For compliance purposes, the permittee elected to demonstrate that the fuel combusted will not exceed the potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input (see Appendix G of the permit). *{Permitting Note: Maximum expected SO_2 emissions from each turbine are approximately 1.9 lb/hr and 0.5 lb/hr for NG and ULSD, respectively.}*

e. The mass emission rate standards are based on a turbine inlet temperature condition of 59 °F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

f. 40 CFR 60, Subpart KKKK as described in 40 CFR 60.4320(a).

g. 40 CFR 60, Subpart KKKK as described in 40 CFR 60.4350(g).

{Permitting Note: In combination with the annual restriction on hours of operation, the above emissions standards effectively limit annual potential emissions from both gas turbines to: 16.5 tons/year of CO, 121.7 tons/year of NOx, 11.3 tons/year of PM/PM_{10}, 6.6 tons/year of SO_2, 0.8 tons/year of SAM, and 4.7 tons/year of VOC.}

[Applicant requested; Rules 62-4.070(3), 62-210.200(Definitions-PTE) and 62-212.400(PSD), F.A.C.; and 40 CFR 60, Subpart KKKK]

11. Unconfined Particulate Emissions: During the construction period, unconfined PM emissions shall be minimized by dust suppressing techniques such as covering, confining, or applying water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

12. Standard Testing Requirements: See Appendix D (Standard Testing Requirements) of this permit for notification, testing, recordkeeping and reporting requirements regarding a performance test. [Rules 62-204.800 and 62-297.100, F.A.C.; Appendix D of this permit; and 40 CFR 60, Appendix A]

13. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1-4	Methods for Determining Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content: These methods shall be performed as necessary to support other methods.
5	Method for Determining Particulate Matter Emissions
7E	Determination of NOx Emissions from Stationary Sources (Instrumental)
6 or 6C	Determination of SO_2 Emissions from Stationary Sources
8	Determination of SAM and SO_2 Emissions from Stationary Sources
9	Visual Determination of Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography *{Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}*
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxide Emissions Rates
20	Determination of NOx, SO_2, and Diluent Emissions from Stationary Combustion Turbines
25A	Determination of Total Gaseous Organic Concentrations Using a Flame Ionization Analyzer

The methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used for compliance testing unless prior written approval is received from the Administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to Rule 62-297.620, F.A.C. [Rule 62-204.800, F.A.C. and 40 CFR 60, Appendix A]

14. Testing Requirements: Initial and subsequent performance tests shall be conducted between 90% and 100% of permitted capacity in accordance with the requirements of Rule 62-297.310(2), F.A.C. [Rules 62-297.310(2) and (7)(a), F.A.C.; 40 CFR 60.8; and Appendix D of this permit]

15. Initial Compliance Demonstration: Initial compliance tests shall be conducted within 60 days after achieving the maximum production rate at which the units will be operated, but not later than 180 days after the initial startup. In accordance with the test methods specified in this permit, each turbine exhaust stack shall be tested for each fuel to demonstrate compliance with the emission limits for CO, NOx and visible emissions. For each test run (including visible emissions tests), CO and NOx emissions recorded by the required CEMS shall be reported. [Rule 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8; and Appendix D of this permit]

16. Annual Compliance Testing: During each federal fiscal year (October 1st to September 30th), annual compliance tests for visible emissions shall be conducted. For each visible emissions test, emissions of CO and NOx recorded by the CEMS shall also be reported. [Rules 62-297.310(7)(a) and (b), F.A.C. and Appendix D of this permit]

17. Initial and Subsequent Compliance Demonstration for NOx: See 40 CFR 60.4400 and 4405 in Appendix G (NSPS Subpart KKKK Requirements for Stationary Combustion Turbines) of this permit for the initial and subsequent compliance demonstration for NOx. [40 CFR 60.4400 and 60.4405; and Appendices A and G of this permit]

18. Initial and Subsequent Compliance Demonstration for Sulfur: See 40 CFR 60.4415 in Appendix G (NSPS Subpart KKKK Requirements for Stationary Combustion Turbines) of this permit for the initial and subsequent compliance demonstration for SO_2. A one-time compliance test on one CT shall be conducted for SO_2 mass emissions in order to satisfy compliance with the mass limit and the quality of the NG and ULSD. Afterwards, the use of NG and ULSD in accordance with the permit and 40 CFR 60.4415 will be used as a surrogate for SO_2 emissions. [40 CFR 60.4415; Appendices A and G of this permit; and Rule 62-4.070(3), F.A.C.]

19. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 3-hour rolling average CO emissions standards and with the 4-hour rolling average NOx emission standards based on data collected by the required CEMS. Within 45 days of conducting any RATA on a CEMS that represents the annual compliance test, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. If the RATA on a CEMS was not conducted as an annual compliance test, then the results can be submitted with the SIP Quarterly or Semiannual Report. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which also reduces emissions of PM. [Rules 62-4.070(3) and 62-297.310(7)(a) and (b), F.A.C.]

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

EXCESS EMISSIONS

{Permitting Note: Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

21. Definitions: Rule 62-210.200(Definitions), F.A.C., defines the following terms.

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.

    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner

22. Excess Emissions Allowed - SIP. See Appendix C (Common Conditions) of this permit. [Rule 62-210.700(1), F.A.C. and Appendix C of this permit]

23. Excess Emissions Prohibited - SIP. See Appendix C (Common Conditions) of this permit. [Rule 62-210.700(4), F.A.C. and Appendix C of this permit]

24. Allowable SIP CO and NOx Data Exclusions: Provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions are minimized, CO and NOx CEMS data collected during periods of startup, shutdown and malfunction may be excluded from the 3-hr rolling average and 4-hr rolling average, respectively, compliance demonstrations only in accordance with the following requirements. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown and malfunction) may be excluded. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

a. *Startup*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 10 minutes of CEMS data shall be excluded for each gas turbine startup. For startups of less than 10 minutes in duration, only those minutes attributable to startup shall be excluded.

b. *Shutdown*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 10 minutes of CEMS data shall be excluded for each gas turbine shutdown. For shutdowns less than 10 minutes in duration, only those minutes attributable to shutdown shall be excluded.

c. *Malfunction*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than 120 minutes of CEMS data shall be excluded in a 24-hour period for each gas turbine due to malfunctions. Within one (1) working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data.

The permittee shall notify the Compliance Authority within one working day of discovering any emissions in excess of a CEMS standard subject to the specified averaging period. All such reasonably preventable emissions shall be included in any CEMS compliance determinations. All valid emissions data (including data collected during startup, shutdown and malfunction) shall be used to report annual emissions for the Annual Operating Report. [Rules 62-4.070(3), 62-210.200, 62-210.370(3) and 62-210.700, F.A.C.]

25. Excess Emissions NSPS - NOx: See 40 CFR 60.4350 and 4380 in Appendix G (NSPS Subpart KKKK Requirements for Stationary Combustion Turbines) of this permit. [40 CFR 60.4350 and 60.4380]

26. Excess Emissions NSPS - SO_2: See 40 CFR 60.4385 in Appendix G (NSPS Subpart KKKK Requirements for Stationary Combustion Turbines) of this permit. [40 CFR 60.4385

CONTINUOUS EMISSIONS MONITORING SYSTEMS (CEMS) REQUIREMENTS

27. CEMS: The permittee shall install, calibrate, maintain and operate the diluent CEMS to measure CO_2 emissions and CEMS to measure and record the emissions of CO and NOx from each gas turbine in a manner sufficient to demonstrate continuous compliance with the emission standards of this section. All continuous monitoring systems shall be installed and functioning within the required performance specification by the time of the initial performance tests.

a. *NOx Monitor:* Each NOx monitor shall be certified pursuant to the specifications of 40 CFR 75. Quality assurance procedures shall conform to the requirements of 40 CFR 75. The annual and required Relative Accuracy Test Audit (RATA) tests required for the NOx monitor shall be performed using EPA Method 7E or 20 in 40 CFR 60, Appendix A.

b. *CO Monitor:* Each CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The annual and required RATA tests required for the CO monitor shall be performed using EPA Method 10 in 40 CFR 60, Appendix A, and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

c. *SO_2 Monitoring:* SO_2 monitoring will be in accordance with 40 CFR 75, Appendix D requirements (using sulfur content and fuel flow rates).

d. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

[Rules 62-4.070(3) and 62-297.520, F.A.C.; 40 CFR 75; and Appendix E of this permit]

28. CEMS Data Requirements: The CEMS shall be installed, calibrated, maintained and operated in the gas turbine stacks to measure and record the emissions of CO and NOx in a manner sufficient to demonstrate compliance with the CEMS-based emission limits of this section. The CEMS shall express the results in units of ppmvd corrected to 15% oxygen. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable NOx standards of 40 CFR 60, Subpart KKKK, Table 1. The permittee shall be in compliance with the terms and conditions contained in Appendix E, Standard Continuous Monitoring Requirements, of this permit. [Rule 62-4.070(3), F.A.C. and Appendix E of this permit]

29. CEMS Annual Emissions Requirement: The owner or operator shall use data from the NOx and CO CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rule 62-210.370(3), F.A.C., Annual Operating Report. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit. [Rules 62-210.200(Definitions) and 62-210.370(3), F.A.C.]

REPORTING AND RECORDKEEPING REQUIREMENTS

30. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. [Rule 62-297.310(8), F.A.C. and Appendix D of this permit]

31. Monitoring of Capacity: The permittee shall monitor and record the heat input of each CT on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). This shall be achieved through monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75, Appendix D, and recording the data using a monitoring component of the CEMS required above. [Rule 62-4.070(3), F.A.C. and Appendix E of this permit]

32. Monthly Operations Summary: By the 15th calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the combustion turbine for the previous month of operation: fuel consumption, hours of operation and the updated calendar year totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. [Rule 62-4.070(3), F.A.C.]

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

    a. *Natural Gas Sulfur Limit*: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. A representative sample shall be collected using ASTM D5287. Methods for determining the sulfur content of the natural gas shall be ASTM methods D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gaseous Processors Association Standard 2377, or more recent versions, or through provisions listed in 40 CFR 60, Subpart KKKK that allows alternate NG fuel sulfur monitoring.

    b. *ULSD Fuel Sulfur Limit*: Compliance with the fuel sulfur limit for ULSD fuel shall be demonstrated by keeping each bill of lading report obtained from the vendor indicating the sulfur content, percent by weight, of the ULSD fuel being delivered. A representative sample shall be collected using ASTM D5287. Methods for determining the sulfur content of the ULSD fuel shall be ASTM methods D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gaseous Processors Association

Standard 2377, or more recent versions, or through provisions listed in 40 CFR 60, Subpart KKKK that allows alternate sulfur monitoring for ULSD.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 60.4415. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.; 40 CFR 60.4415; and Appendix G of this permit]

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

35. CEMS RATA Reports: At least 15 days prior to conducting any RATA on a CEMS, the permittee shall notify the Compliance Authority of the schedule (letter, email, fax, or phone call). A summary of the RATA reports shall be provided upon written request of the Compliance Authority and in the SIP Excess Emissions Report as specified in specific condition 36. [Rule 62-4.070(3), F.A.C.]

36. Excess Emissions Reporting:

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

b. *SIP Excess Emissions Report*: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority of the following for each gas turbine using the NSPS format in 40 CFR 60.7(c), Subpart A: a summary of the 4-hour rolling average NOx compliance periods for the quarter; a summary of the 3-hour rolling average CO compliance periods for the quarter; a summary of NOx and CO data excluded for the quarter; a summary of any RATA tests performed during the quarter; and a summary of the CEMS systems monitor availability for the quarter.

(1) If four consecutive quarterly reports demonstrate compliance with the CEMS-based emissions standards, the reporting frequency may be reduced to semiannual reporting. As part of the fourth consecutive satisfactory quarterly report, the permittee shall provide written notification of its intent to reduce the reporting frequency to a semiannual basis. The notification shall include a statement that the units were in full compliance during the four consecutive quarters and that reporting will be reduced to a semiannual basis. Semiannual reports shall include above information required for each quarter in the semiannual period. The permittee shall continue to comply with all other record keeping and monitoring provisions.

(2) If reports are being submitted on a semiannual basis and a unit is not in compliance with the CEMS-based emissions standards, the permittee shall immediately (within one day of detection) notify the Compliance Authority of the compliance status and reestablish quarterly reporting beginning with the current quarter. If compliance is reestablished for four consecutive quarters, semiannual reporting may resume as specified above.

c. *NSPS Reporting*: For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under 40 CFR 60, Subpart KKKK, the owner or operator must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR

60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown and malfunction.

{Note: If there are no periods of excess emissions as defined in 40 CFR 60, Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semiannual Report.}

[Rules 62-4.070(3), 62-4.130, 62-204.800 and 62-210.700(6), F.A.C.; and 40 CFR 60.7 and 60.4375]

37. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility in accordance with Rule 62-210.370, F.A.C., and Appendix C (Common Conditions) of this permit. Annual operating reports shall be submitted to the Compliance Authority by May 1, 2009, for calendar year 2008, and April 1st thereafter. [Rule 62-210.370(3), F.A.C.]

CONTENTS

CITATION FORMATS AND GLOSSARY OF COMMON TERMS

CITATION FORMATS

The following illustrate the formats used in the permit to identify applicable requirements from permits and regulations.

Old Permit Numbers

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

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

New Permit Numbers

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

Where: "099" represents the specific county ID number in which the project is located

"2222" represents the specific facility ID number for that county

"001" identifies the specific permit project number

"AC" identifies the permit as an air construction permit

"AF" identifies the permit as a minor source federally enforceable state operation permit

"AO" identifies the permit as a minor source air operation permit

"AV" identifies the permit as a major Title V air operation permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the preconstruction review requirements of the Prevention of Significant Deterioration of Air Quality

"FL" means that the permit was issued by the State of Florida

"317" identifies the specific permit project number

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

GLOSSARY OF COMMON TERMS

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

ARMS: Air Resource Management System (Department's database)

BACT: best available control technology

Btu: British thermal units

CAM: compliance assurance monitoring

CEMS: continuous emissions monitoring system

cfm: cubic feet per minute

CFR: Code of Federal Regulations

CO: carbon monoxide

CO_2: carbon dioxide

COMS: continuous opacity monitoring system

DEP: Department of Environmental Protection

Department: Department of Environmental Protection

dscfm: dry standard cubic feet per minute

EPA: Environmental Protection Agency

ESP: electrostatic precipitator (control system for reducing particulate matter)

EU: emissions unit

F.A.C.: Florida Administrative Code

F.D.: forced draft

F.S.: Florida Statutes

FGR: flue gas recirculation

Fl: fluoride

ft^2: square feet

ft^3: cubic feet

gpm: gallons per minute

gr: grains

gr/dscf: grains per dry standard cubic feet

HAP: hazardous air pollutant

Hg: mercury

HHV: higher heating value

I.D.: induced draft

ID: identification

kPa: kilopascals

lb: pound

MACT: maximum achievable technology

MMBtu: million British thermal units

MSDS: material safety data sheets

MW: megawatt

NESHAP: National Emissions Standards for Hazardous Air Pollutants

NOx: nitrogen oxides

NSPS: New Source Performance Standards

O&M: operation and maintenance

O_2: oxygen

Pb: lead

PM: particulate matter

PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less

PSD: prevention of significant deterioration

psi: pounds per square inch

PTE: potential to emit

RACT: reasonably available control technology

RATA: relative accuracy test audit

SAM: sulfuric acid mist

scf: standard cubic feet

scfm: standard cubic feet per minute

SIC: standard industrial classification code

SNCR: selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)

SO_2: sulfur dioxide

TPH: tons per hour

TPY: tons per year

UTM: Universal Transverse Mercator coordinate system

VE: visible emissions

VOC: volatile organic compounds

GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the F.S. or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, F.S.. Such evidence

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

10. The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.
11. This permit is transferable only upon Department approval in accordance with Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology (applicable);
    b. Determination of Prevention of Significant Deterioration (applicable); and
    c. Compliance with New Source Performance Standards (applicable).
14. The permittee shall comply with the following:
    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
    c. Records of monitoring information shall include:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

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

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(Definitions), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

{Permitting Note: Rule 62-210.700 (Excess Emissions), F.A.C., cannot vary any NSPS or NESHAP provision.}

RECORDS AND REPORTS

10. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]
11. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(3), F.A.C.]

STANDARD TESTING REQUIREMENTS

Unless otherwise specified in the permit, the following testing requirements apply to all emissions units at the facility.

COMPLIANCE TESTING REQUIREMENTS

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

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

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

4. Applicable Test Procedures

   a. *Required Sampling Time.*

      (1) Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

      (2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

         (a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

         (b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

         (c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

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

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

d. *Allowed Modification to EPA Method 5.* When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

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

5. <u>Determination of Process Variables</u>

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

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

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

6. <u>Sampling Facilities</u>: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

a. *Permanent Test Facilities.* The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

b. *Temporary Test Facilities.* The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department or its designee elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department or its designee and remain on the emissions unit until the test is completed.

c. *Sampling Ports.*

(1) All sampling ports shall have a minimum inside diameter of 3 inches.

(2) The ports shall be capable of being sealed when not in use.

(3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

(4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

(5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms.*

(1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

(2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

(3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

(4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform.*

(1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

(2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power.*

(1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

(2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

(1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

(a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

(b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

(c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

(2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.

(3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

[Rule 62-297.310(6), F.A.C.]

7. Frequency of Compliance Tests: The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

a. *General Compliance Testing.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

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

   (a) Did not operate; or

   (b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,

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

   (a) Visible emissions, if there is an applicable standard;

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

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

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9. The owner or operator shall notify the Department or its designee, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

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

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

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

RECORDS AND REPORTS

8. Test Reports:

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department or its designee on the results of each such test.

b. The required test report shall be filed with the Department or its designee as soon as practical but no later than 45 days after the last sampling run of each test is completed.

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

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.

15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

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

STANDARD CONTINUOUS MONITORING REQUIREMENTS

The new SCCT peaking units SCCT 4A and SCCT 4B (EU-041 and 042, respectively) are subject to the following requirements for the new continuous emissions monitoring systems (CEMS) required for CO and NOx emissions and CO_2 for diluent.

CEMS OPERATION PLAN

1. CEMS Operation Plan: The permittee shall create and implement a plan for the proper installation, calibration, maintenance, and operation of each CEMS required by this permit. The permittee shall submit the CEMS Operation Plan to the Bureau of Air Monitoring and Mobile Sources for approval prior to CEMS installation. The CEMS Operation Plan shall become effective 60 days after submittal or upon its approval. If the CEMS Operation Plan is not approved, the permittee shall submit a new or revised plan for approval. *{Permitting Note: The Department maintains both guidelines for developing a CEMS Operation Plan and example language that can be used as the basis for the facility-wide plan required by this permit. Contact the Emissions Monitoring Section of the Bureau of Air Monitoring and Mobile Sources at 850/488-0114.}* [Rule 62-4.070(3), F.A.C.]

MONITORS, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. Span Values and Dual Range Monitors: The permittee shall set appropriate span values for the CEMS based on the emissions standards and range of operation. If necessary, the permittee shall install dual range monitors in accordance with the CEMS Operation Plan. [Rule 62-4.070(3), F.A.C.]
3. Diluent Monitor: If required by permit to correct the CEMS output to the oxygen concentrations specified in the applicable emissions standard, the permittee shall either install an oxygen monitor or install a CO_2 monitor and use an appropriate F-Factor computational approach. [Rule 62-4.070(3), F.A.C.]
4. Moisture Correction: If necessary, the permittee shall install a system to determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). [Rule 62-4.070(3), F.A.C.]
5. Continuous Flow Monitor: For compliance with mass emission flow rate standards, the permittee shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 6. Alternatively, the permittee may install a fuel flow monitor and use an appropriate F-Factor computational approach to calculate stack exhaust flow rate. *{Permitting Note: The CEMS Operation Plan will contain additional details and procedures for CEMS installation.}* [Rule 62-4.070(3), F.A.C.]
6. Performance Specifications: The permittee shall evaluate the "acceptability" of each CEMS by conducting the appropriate performance specification. CEMS determined to be "unacceptable" shall not be considered "installed" for purposes of meeting the timelines of this permit. For CO monitors, the permittee shall conduct Performance Specification 4 of 40 CFR 60, Appendix B. For NOx monitors, the permittee shall conduct Performance Specification 2 of 40 CFR 60, Appendix B, or the applicable CEMS certification procedures of 40 CFR 75, Appendix A, Section 6. [Rule 62-4.070(3), F.A.C.; 40 CFR 60; and 40 CFR 75]
7. Quality Assurance: The permittee shall follow the quality assurance procedures of 40 CFR 60, Appendix F. For NOx, the permittee may follow the applicable quality assurance requirements of 40 CFR 75, Appendix B. For CO, the required relative accuracy test audit (RATA) tests shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. For NOx, the RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR 60. [Rule 62-4.070(3), F.A.C.; 40 CFR 60; and 40 CFR 75]

CALCULATION APPROACH FOR SIP COMPLIANCE

8. CEMS for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the permittee shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit. [Rule 62-4.070(3), F.A.C.]
9. CEMS Data: Each CEMS shall monitor and record emissions during all operations and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. Unless otherwise specified in this permit, all data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs,

calibration checks, zero adjustments, and span adjustments. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. [Rule 62-4.070(3), F.A.C.]

10. Operating Hours and Operating Days: For purposes of this Appendix, the following definitions shall apply. An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit. [Rule 62-4.070(3), F.A.C.]

11. Valid Hourly Averages: Each CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

    a. Hours that are not operating hours are not valid hours.

    b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

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

12. Calculation Approaches: The permittee shall implement the calculation approach specified by this permit for each CEMS, as follows:

    a. *Daily Averages*:

    b. *Rolling 30-day Average.*

    c. *4-Hour Rolling Average (NO_X)*: Compliance with the 4-hour rolling average shall be determined after each operating hour by calculating and recording the arithmetic average of all valid hourly averages for the previous 4 operating hours (compliance period).

    d. *3-Hour Rolling Average (CO)*: Compliance with the 3-hour rolling average shall be determined after each operating hour by calculating and recording the arithmetic average of all valid hourly averages for the previous 3 operating hours (compliance period).

    e. *Rolling 12*-month Totals:

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

13. Minimum Valid Hours: At least one valid hourly average shall be used to calculate the emissions over any averaging period specified by this permit. One valid hourly average shall be sufficient to calculate the emissions over any averaging period. [Rule 62-4.070(3), F.A.C.]

MONITOR AVAILABILITY

14. Monitor Availability: Monitor availability shall be calculated on a quarterly basis for each emission unit as the number of valid hourly averages obtained by the CEMS, divided by the number of operating hours, times 100%. The monitor availability calculation shall not include periods of time where the monitor was functioning properly, but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit, or relative accuracy audits (RAA). Monitor availability for each CEMS shall be 95% or

greater in any calendar quarter. Monitor availability shall be reported in the quarterly excess emissions report. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit. [Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

15. Definitions:

    a. *Excess Emissions* (under the Florida SIP) are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction.

    b. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

    c. *Shutdown* means the cessation of the operation of an emissions unit for any purpose.

    d. *Malfunction* means any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

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

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

17. Data Exclusion Procedures for SIP Compliance: As per the procedures in this condition, limited amounts of CO and NO_X CEMS emissions data may be excluded from the corresponding compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

    a. *Excess Emissions.* For purposes of SIP-based permit limits, excess emissions data collected during periods of startup and shutdown may be excluded from compliance calculations as allowed by the permit standards.

    b. *Limiting Data Exclusion.* If the compliance calculation using all valid CEMS emission data (as defined in this Appendix) indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

    c. *Event Driven Exclusion.* The excess emissions must occur due to an underlying event (startup or shutdown). If there is no underlying event, then no data may be excluded.

    d. *Continuous Exclusion.* Data shall be excluded on a continuous basis per event. Data from discontinuous periods shall not be excluded for the same underlying event.

    e. *Reporting Excluded Data.* These procedures for excluding SIP-based excess emissions from compliance calculations are not necessarily the same procedures used for "excess emissions" as defined by federal rules. Semiannual reports required by this permit shall indicate the duration of data excluded from SIP compliance calculations as well as the number of excess emissions as defined in the applicable federal rules.

    {Permitting Note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.} [Rule 62-210.700(4), F.A.C.]

18. Notification Requirements: The permittee shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate non-compliance for a given averaging period. [Rule 62-4.070(3), F.A.C.]

CALCULATING AND REPORTING ANNUAL EMISSIONS

19. CEMS for Calculating Annual Emissions: As defined by this Appendix, all valid data shall be used when calculating annual emissions.

    a. Annual emissions shall include data collected during startup, shutdown, and malfunction periods.

    b. Annual emissions shall include data collected during periods when the emission unit is not operating, but emissions are being generated (for example, firing fuel to warm up a process for some period of time prior to the emission unit's "official" startup).

    c. Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit, or RAA. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

    d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

20. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average that begins at the top of each hour. For each hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the permittee shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hour block average.

21. Emissions Calculation: Annual emissions shall be calculated as the sum of all valid emissions occurring during the year.

22. Reporting Annual Emissions: The permittee shall use data from each required CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rules 62-210.370(3) and 62-212.300(1)(e), F.A.C. [Rule 62-4.070(3), F.A.C.]

NSPS SUBPART A, GENERAL CONDITIONS

Emissions units subject to a New Source Performance Standards of 40 CFR 60 are also subject to the applicable requirements of Subpart A, General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

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

NSPS SUBPART KKKK, REQUIREMENTS FOR STATIONARY COMBUSTION TURBINES

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part.

§ 60.4310 What types of operations are exempt from these standards of performance?

(a) Not applicable (NA)

(b) NA

(c) NA

(d) NA

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NOx) and sulfur dioxide (SO_2).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NOx)?

(a) You must meet the emission limits for NOx specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NOx.

§ 60.4325 What emission limits must I meet for NOx if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1) or (a)(2) of this section.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

(b) NA.

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) NA.

Monitoring

§ 60.4335 How do I demonstrate compliance for NOx if I use water or steam injection?

(a) If you are using water or steam injection to control NOx emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NOx monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NOx emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu).

(2) NA.

(3) NA.

(4) NA.

§ 60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?

(a) NA.

(b) NA.

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NOx CEMS is chosen:

(a) Each NOx diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NOx diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NOx monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NOx emission rate for the hour.

(c) Each fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flow meters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NOx and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOx emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NOx concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NOx diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_X)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flow meter(s), *e.g.* , calculated using Equation D–15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) NA.

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) NA.

(b) NA.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel? NA.

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.* , flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§ 60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§ 60.4380 How are excess emissions and monitor downtime defined for NOx?

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NOx control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour rolling average NOx emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4- hour rolling average NOx emission rate" is the arithmetic average of the average NOx emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NOx emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NOx emission rate is obtained for at least 3 of the 4 hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NOx concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) NA.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel obtained using daily sampling, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine? NA.

§ 60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NOx?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NOx performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) For each test run:

(ii) Measure the NOx and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flow meter (or flow meters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NOx emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NOx emission rate in lb/MWh.

(2) Sampling traverse points for NOx and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NOx and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NOx concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5 ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NOx concentration during the stratification test; or

(B) For turbines with a NOx standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NOx concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3 ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points.

(C) NA.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) NA.

(3) If water or steam injection is used to control NOx with no additional post-combustion NOx control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NOx emissions limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NOx emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NO_X-diluent CEMS?

If you elect to install and certify a NOx-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NOx emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NOx emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters? NA.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17).

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

(2) NA.

(3) NA.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

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

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Excess emissions means a specified averaging period over which either (1) the NOx emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Table 1 to Subpart KKKK of Part 60-Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NOx emission standard
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh)

TECO

TAMPA ELECTRIC

July 16, 2009

Ms. Trina Vielhauer
Chief, Bureau of Air Regulation
Florida Department Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7977 6923 8139

Via Email Notification
Trina.Vielhauer@dep.state.fl.us

Ms. Gracy Danois
U.S. Environmental Protection Agency, Region IV
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7977 6924 3241

RECEIVED
JUL 17 2009
BUREAU OF AIR REGULATION

Re: Tampa Electric Company
Big Bend Power Station Unit SCCT4
Notification of Certification and Performance Testing Dates
Air Permit No. 0570039-040-AC

Dear Ms. Vielhauer and Ms. Danois:

On July 8, 2009, TEC submitted the Monitoring Plan and Test Protocol for Big Bend Station (BBS) Unit SCCT 4. TEC is required by 40 CFR Part 60.8 and 40 CFR Part 75.61 respectively to perform and notify of performance and CEM certification testing. TEC is hereby submitting notification that the anticipated performance and CEM certification testing will be conducted during the week of August 30th, 2009 for BBS SCCT 4. CEM shelter work for SCCT 4 will begin during the week of August 3rd, 2009. The CEM shelter work consists of the cycle response time, 7-day drift, linearity, calibrations and DAHS certification. The performance testing that will be held later in August will consist of the RATA and stratification testing.

As the schedule changes TEC will keep the FDEP and EPCHC updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 228-4740.

Sincerely,

Byron Burrows

Byron Burrows, P.E.
Alternate Designated Representative
Environmental, Health & Safety

ENVP\Admin\Staktest\2009\BB127 BB SCCT4 Cert Notification

cc: Mr. Bruce Mitchell – FDEP
Ms. Mara Grace Nasca - FDEP SW District
Mr. Errin Pichard - Errin.Prichard@dep.state.fl.us
Mr. Jason Waters - watersj@epchc.org; Fax: 813-627-2660
CEM Section - AIREMS@dep.state.fl.us

TAMPA ELECTRIC

RECEIVED

JUL 08 2009

BUREAU OF AIR REGULATION

July 7, 2009

Ms. Gracy Danois
U.S. Environmental Protection Agency, Region IV
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7977 4144 6254

Ms. Trina Vielhauer
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7967 5442 5010

Re: Tampa Electric Company
Big Bend Power Station Unit SCCT4
Anticipated Commercial Operations Notification
Project No. 0570039-040-AC

Dear Ms. Danois and Ms. Vielhauer:

Tampa Electric Company (TEC) is notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the anticipated date of initial commercial operations as required by 40 CFR 75.61(a)(2)(i), the designated representative for an affected unit shall submit written notification: For a new unit of the planned date when a new unit will commence commercial operation. TEC hereby gives notice that commercial operation for environmental purposes, of Big Bend Power Station Unit SCCT 4 will be on or about August 21, 2009. Big Bend Power Station Unit SCCT 4 consists of two (2) Pratt & Whitney FT8-3 SwiftPac aero derivative simple cycle dual fuel (natural gas/fuel oil) combustion turbine serving a single generator with a nominal output of 62 megawatt (MW).

As the schedule changes TEC will keep the EPA and FDEP updated. If you have any questions, please call me or Thuy Nguyen at (813) 228-4654.

Sincerely,

Byron Burrows, P.E.
Alternate Designated Representative
Environmental, Health & Safety

ENVP\Admin\JMW204 CT 4 Anticipated COD

cc: Mr. Bruce Mitchell – FDEP
Ms. Mara Grace Nasca, FDEP SW District
Mr. Sterlin Woodard, EPCHC

TAMPA ELECTRIC COMPANY
P. O. BOX 111 TAMPA, FL 33601-0111

(813) 228-4111

CUSTOMER SERVICE:
HILLSBOROUGH COUNTY (813) 223-0800
POLK COUNTY (863) 299-0800
ALL OTHER COUNTIES 1 (888) 223-0800

TECO.

TAMPA ELECTRIC

RECEIVED

JUL 08 2009

BUREAU OF AIR REGULATION

July 7, 2009

Ms. Trina Vielhauer
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7967 5442 5010

Re: Tampa Electric Company (TEC)
Big Bend Power Station Unit SCCT4
Notification of Anticipated Startup Date
Air Permit No. 0570039-040-AC

Dear Ms. Vielhauer:

Tampa Electric Company (TEC) is notifying the Florida Department of Environmental Protection (FDEP) of the anticipated dates of initial startup as required by 40 CFR Part 52.129(c)(7)(i), which states that the anticipated date of initial startup of source must be made not more than 60 days or less than 30 days prior to initial startup. TEC hereby gives notification that the anticipated startup of Big Bend Power Station (BBPS) Unit SCCT 4 is August 6, 2009. BBPS Unit SCCT4 consists of two (2) Pratt & Whitney FT8-3 SwiftPac aero derivative simple cycle dual fuel (natural gas/fuel oil) combustion turbine serving a single generator with a nominal output of 62 megawatt (MW).

As the schedule changes TEC will keep the FDEP updated. If you have any questions, please call me or Andrew (Thuy) Nguyen (813) 228-4654.

Sincerely,

Byron T. Burrows, P.E.
Alternate Designated Representative
Environmental, Health & Safety

ENVP/admin/JMW203 BBS CT4 Anticipated Startup Notification

c: Mr. Bruce Mitchell – FDEP
Ms. Mara Grace Nasca, FDEP SW District
Mr. Sterlin Woodard, EPCHC

TAMPA ELECTRIC

RECEIVED

JUL 09 2009

BUREAU OF AIR REGULATION

July 9, 2009

Ms. Gracy Danois
U.S. Environmental Protection Agency, Region IV
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7977 4925 6401

Ms. Trina Vielhauer
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7967 6222 2117

Mr. Sterlin Woodard, P.E.
Environmental Protection Commission of Hillsborough County
3629 Queen Palm Drive
Tampa, FL 33619

Via FedEx
Airbill No. 7967 6223 9580

Re: Tampa Electric Company (TEC)
Big Bend Power Station Unit SCCT4
Revised Notification of Planned Startup Date
Air Permit No. 0570039-040-AC
ORISPL 645

Dear Ms. Danois, Ms. Vielhauer, and Mr. Woodard:

Tampa Electric Company (TEC) is providing a revised notification to the Florida Department of Environmental Protection (FDEP), Environmental Protection Commission of Hillsborough County (EPC), and the Environmental Protection Agency of the planned startup as required by 40 CFR 75.61(a)(2)(i), TEC hereby gives notification that the revised planned startup of Big Bend Station (BBS) Unit SCCT 4 is August 25, 2009. Pursuant to 40 CFR 75.61(a)(2)(ii), TEC will notify you within seven (7) days of commencement of commercial operation if the actual date is different than is currently planned. BBS Unit SCCT4 consists of two (2) Pratt & Whitney FT8-3 SwiftPac aero derivative simple cycle dual fuel (natural gas/fuel oil) combustion turbine serving a single generator with a nominal output of 62 megawatt (MW).

If you have any questions, please call me at (813) 228-1282.

Sincerely,

Byron T. Burrows, P.E.
Alternate Designated Representative
Environmental, Health & Safety

ENVP/admin/JMW203 BBS CT4 Anticipated Startup Notification

c: Mr. Bruce Mitchell – FDEP
Ms. Mara Grace Nasca, FDEP SW District
Mr. Robert L. Miller, EPA HQ

TAMPA ELECTRIC COMPANY
P. O. BOX 111 TAMPA, FL 33601-0111
(813) 228-4111

CUSTOMER SERVICE:
HILLSBOROUGH COUNTY (813) 223-0800
POLK COUNTY (863) 299-0800
ALL OTHER COUNTIES 1 (888) 223-0800

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TAMPAELECTRIC.COM

Florida Department of Environmental Protection

Memorandum

TO: Joe Kahn, Division of Air Resource Management

THROUGH Trina Vielhauer, Bureau of Air Regulation

THROUGH: Syed Arif, New Source Review Section

FROM: Bruce Mitchell, New Source Review Section

DATE: December 8, 2008

SUBJECT: Project No. 0570039-040-AC
Tampa Electric Company
Big Bend Station
Two Simple Cycle Combustion Turbines-Generator Peaking Project

The Final Permit for this project is attached for your approval and signature, which authorizes the construction of two simple cycle combustion turbine (SCCT) peaking units, with one associated electrical generator, and one emergency diesel engine/generator set at the existing facility. The construction will take place at the existing Big Bend Station located at 13031 Wyandotte Road in Apollo Beach, Hillsborough County, Florida. The project results in a minor source air construction permit and was not subject to Prevention of Significant Deterioration (PSD) preconstruction review.

The Department distributed an Intent to Issue Permit package on November 19, 2008. The applicant published the Public Notice of Intent to Issue in The Tampa Tribune on November 21, 2008. The Department received the proof of publication on November 26, 2008. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed. No comments on the Draft Permit were received from the public, the Environmental Protection Commission of Hillsborough County or the applicant.

I recommend your approval of the attached Final Permit for this project.

Attachments

PERMITTEE

Tampa Electric Company
P.O. Box 111
Tampa, Florida 32178-0111

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation, New Source Review Section
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

PROJECT

Project No. 0570039-040-AC
Big Bend Station

This project authorizes the construction of two simple cycle combustion turbine (SCCT) peaking units, with one associated electrical generator, and one emergency diesel engine/generator set at the existing facility. The construction will take place at the existing Big Bend Station located at 13031 Wyandotte Road in Apollo Beach, Hillsborough County, Florida. The project results in a minor source air construction permit and was not subject to Prevention of Significant Deterioration (PSD) preconstruction review.

NOTICE AND PUBLICATION

The Department distributed an Intent to Issue Permit package on November 19, 2008. The applicant published the Public Notice of Intent to Issue in The Tampa Tribune on November 21, 2008. The Department received the proof of publication on November 26, 2008. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

COMMENTS

No comments on the Draft Permit were received from the public, the Environmental Protection Commission of Hillsborough County or the applicant.

CONCLUSION

The final action of the Department is to issue the permit as drafted and publicly noticed.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

Authorized Representative:
Paul L. Carpinone, Director, Environmental Health and Safety

Project No. 0570039-040-AC
Big Bend Station
Two Simple Cycle Combustion Turbine Peaking Units

Tampa Electric Company operates the existing Big Bend Station in Hillsborough County located at 13031 Wyandotte Road in Apollo Beach, Florida. This final air construction permit authorizes the construction of two simple cycle combustion turbine (SCCT) peaking units, with one associated electrical generator, and one emergency diesel engine/generator set at the existing facility. This permit is issued pursuant to Chapter 403, Florida Statutes (F.S.).

Any party to this order has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

Trina L. Vielhauer
12/8/08

Trina L. Vielhauer, Chief
Bureau of Air regulation
(Date)

TLV/sa/bm

NOTICE OF FINAL PERMIT

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Determination and the Final Permit) was sent by electronic mail (or a link to these documents made available electronically on a publicly accessible server) with received receipt requested before the close of business on 12/10/08 to the persons listed below.

Mr. Paul L. Carpinone, Tampa Electric Company (plcarpinone@tecoenergy.com)
Mr. David M. Lukcic, Tampa Electric Company (dmlukcic@tecoenergy.com)
Mr. Byron T. Burrows, Tampa Electric Company (btburrows@tecoenergy.com)
Mr. Andrew T. Nguyen, Tampa Electric Company (atnguyen@tecoenergy.com)
Mr. Thomas W. Davis, P.E., Environmental Consulting & Technology, Inc. (tdavis@ectinc.com)
Mr. Jerry Campbell, Hillsborough County Environmental Protection Commission (campbell@epchc.org)
Ms. Diana Lee, Hillsborough County Environmental Protection Commission (Lee@epchc.org)
Mr. Roger Zhu, Hillsborough County Environmental Protection Commission (Zhu@epchc.org)
Ms. Vickie Gibson, DEP-BAR (Victoria.Gibson@dep.state.fl.us) (for read file)

Clerk Stamp

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

[signature] (Clerk) 12/10/08 (Date)

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

PERMITTEE:

Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

Authorized Representative:
Mr. Paul L. Carpinone, Director, Environmental Health and Safety

Project No. 0570039-040-AC
Big Bend Station
Two Simple Cycle Combustion Turbines-Generator Peaker Project
SIC No. 4911
Permit Expires December 31, 2010

PROJECT AND LOCATION

This permit authorizes the construction of two simple cycle combustion turbines (SCCT) with one associated electrical generator at the existing Big Bend Station. SCCT 4A and SCCT 4B will be coupled to one common generator having a nominal gross generation capacity of 62 megawatts (MW). Each SCCT will fire pipeline-quality natural gas and ultra low sulfur diesel fuel (ULSD). Each combustion turbine will operate only in the simple cycle mode. The existing facility is located at 13031 Wyandotte Road in Apollo Beach, Hillsborough County. The map coordinates are UTM Zone 17, 361.78 km East and 3075.10 km North.

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

CONTENTS

Joseph Kahn, Director
Division of Air Resource Management

12/10/2008
Effective Date

FACILITY DESCRIPTION

The Tampa Electric Company's Big Bend Station (Big Bend) is a nominal 2,028 MW existing electrical utility plant located in Apollo Beach, Florida. The facility produces electricity for distribution to the grid as a saleable product.

The regulated emissions units at Big Bend include the following: four steam boilers (Units Nos. 1 - 4); four steam turbines; three simple-cycle combustion turbines (SCCT Nos. 1 - 3); solid fuels, fly ash, limestone, gypsum, slag, and bottom ash storage and handling facilities, and fuel oil storage tanks. Units Nos. 1, 2, 3, and 4 have nominal maximum heat inputs of 4037, 3996, 4115 and 4330 million British thermal units (MMBtu) per hour, respectively. Units Nos. 1 - 4 are fired with coal and with petroleum coke (petcoke) in a mixture with coal up to 20.0% petcoke/ 80.0% coal (by weight), or a coal blended with coal residual generated from the Polk Power Station, or a coal/petcoke blend further blended with coal residual generated from the Polk Power Station. The SCCT are fired with No. 2 distillate fuel oil. In addition, there is a ship surface coating operation. The facility has emissions units that are Acid Rain Units and regulated under the Florida Electrical Power Plant Siting Act.

PROJECT DESCRIPTION

The project will consist of constructing one Pratt & Whitney Power Systems (PWPS) FT8-3® SwiftPac® aeroderivative CT-generator unit. It will be designated as SCCT 4A & SCCT 4B. SCCT 4A and SCCT 4B will be coupled to one common generator having a nominal gross generation capacity of 62 MW. Each SCCT will only operate in the peaking service mode for no more than 3,500 hours per year (hr/yr). Each SCCT will be fired with pipeline-quality natural gas (NG) and ultra low sulfur diesel fuel (ULSD). The NG shall contain no more than 2.0 grains of total sulfur per one hundred standard cubic feet (gr S/100 scf) and the ULSD shall contain a maximum sulfur content of 0.0015 percent (%), by weight. Each SCCT will utilize water injection to reduce the emissions of NOx and an oxidation catalyst to reduce the emissions of carbon monoxide (CO) and volatile organic compounds (VOC).

The project will also include the installation of one new Caterpillar 800 kilowatt (kW) emergency stationary reciprocating internal combustion engine (RICE)-generator set. Excluding emergency conditions, the new stationary RICE-generator set will be allowed to operate for approximately two hours per week (100 hr/yr) for routine testing and maintenance purposes. The new emergency stationary RICE will be fired with ULSD. Under this proposal, the projected maximum total ULSD fuel oil usage is 5,720 gallons per year (gal/yr) and entitles it to a categorical exemption in Rule 62-210.300(3)(a)35.d., F.A.C., One or More Emergency Generators Located Within a Single Facility, because it will burn only one fuel type and fire no more than 32,000 gal/yr.

NEW EMISSION UNITS

This permit authorizes construction and installation of the following new regulated emission units:

ARMS ID	Emission Unit (EU) Description
041	SCCT 4A with a common electric generator that it shares with SCCT 4B
042	SCCT 4B with a common electric generator that it shares with SCCT 4A

This permit also authorizes construction and installation of the following emissions unit that is exempt from construction permitting requirements, but certain new source performance standards may still apply. The emissions unit will be included in the Title V Air Operating Permit.

ARMS ID	EU Description
043	One Caterpillar 800 kW emergency RICE-generator set, which is a categorically exempt emissions unit in Rule 62-210.300(3)(a)35.d., F.A.C.

REGULATORY CLASSIFICATION

Title III: The facility is a major source of hazardous air pollutants (HAP).

Title IV: The facility has units subject to the Acid Rain provisions of the Clean Air Act. The new SCCT 4A and SCCT 4B will be subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "Major Source of Air Pollution" in accordance with Rule 62-210.200(Definitions) and Chapter 62-213, F.A.C.

PSD: The facility is a PSD-major facility pursuant to Chapter 62-212, F.A.C.

New Source Performance Standards (NSPS): SCCT 4A and SCCT 4B (Emissions Units 041 and 042, respectively) are subject to 40 CFR 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005).

National Emissions Standards for Hazardous Air Pollutants (NESHAP): SCCT 4A and SCCT 4B are not subject to 40 CFR 63, Subpart YYYY (NESHAP for Stationary Combustion Gas Turbines) because the effectiveness of the regulations were stayed by the U.S. Environmental Protection Agency (EPA) on August 18, 2004, for diffusion flame gas-fired turbines – the type of turbines proposed for this project.

NESHAP: The caterpillar emergency RICE-generator set (Emissions Unit 043) is subject to 40 CFR 63, Subpart ZZZZ (NESHAP for New Stationary RICE) with a site-rating of more than 500 brake horsepower that commences construction after December 1, 2002. However, new stationary RICE that operate exclusively as emergency units are subject only to initial notification requirements.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A.	Citation Formats and Glossary of Common Terms
Appendix B.	General Conditions
Appendix C.	Common Conditions
Appendix D.	Standard Testing Requirements
Appendix E.	Standard Continuous Monitoring Requirements

Appendix F. NSPS Subpart A, General Provisions

Appendix G. NSPS Subpart KKKK, Requirements for Stationary Combustion Turbines

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action: the permit application and additional information received to make it complete; the draft permit package including the Department's Technical Evaluation and Preliminary Determination; publication and comments; and the Department's Final Determination.

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

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Hillsborough County Environmental Protection Commission (HCEPC) office. The mailing address of the HCEPC's Air Quality Division (AQD) is 3629 Queen Palm Drive, Tampa, Florida 33619. The AQD's telephone number is 813/627-2600 and facsimile number is 813/627-2660.

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

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S., and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296 and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C., and follow the application procedures in Chapter 62-4, F.A.C. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

5. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid if construction is not completed within a reasonable time. The Department may extend the expiration date upon a satisfactory showing that an extension is justified. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1) and 62-212.400(12), F.A.C.]

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

7. Source Obligation:

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

    b. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

    [Rule 62-212.400(12), F.A.C.]

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

9. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. This permit does not specify the Acid Rain program requirements. These will be included in the Title V Air Operation Permit. [40 CFR 70; 40 CFR 72; and Chapter 62-213, F.A.C.]

10. Title V Air Operation Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V Air Operation Permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V Air Operation Permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050 and 62-4.220, and Chapter 62-213, F.A.C.]

The specific conditions of this subsection apply to the following emission units after construction is complete.

ARMS ID	Emission Unit Description
041	SCCT 4A with a common electric generator that it shares with SCCT 4B
042	SCCT 4B with a common electric generator that it shares with SCCT 4A

APPLICABLE STANDARDS AND REGULATIONS

1. Emissions Unit Shutdowns for PSD Preconstruction Review Purposes: Upon achieving commercial operation of SCCT 4A and SCCT 4B, existing CT Nos. 1, 2 and 3 shall be shutdown for purposes of PSD preconstruction new source review and credible emissions usage. Pursuant to the definitions at 40 CFR 72.2, commercial operation means "to have begun to generate electricity for sale, including the sale of test generation". The Department and the Compliance Authority shall be sent notification in writing of the shutdown date of each emissions unit for documenting in the data base of the air resource management system (ARMS). [Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.]

2. NSPS Requirements: Each SCCT shall comply with the applicable NSPS in 40 CFR 60 including: Subpart A (General Provisions) and Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005). See Appendix F for the NSPS Subpart A provisions and Appendix G for the NSPS Subpart KKKK provisions. Some separate reporting and monitoring may be required by the individual subparts. [Rule 62-204.800(7)(b), F.A.C.; and 40 CFR 60, Subparts A and KKKK]

EQUIPMENT DESCRIPTION

3. SCCT 4A and SCCT 4B: The permittee is authorized to install, operate and maintain one PWPS FT8-3® SwiftPac® aeroderivative CT-generator peaking unit. SCCT 4A and SCCT 4B will be coupled to one common generator having a nominal gross generation capacity of 62 MW. Each SCCT will be equipped with water injection to minimize NOx emissions and an oxidation catalyst to minimize CO and VOC emissions. Each SCCT will only be operated in the simple cycle mode. Each SCCT will be allowed to fire pipeline-quality natural gas (NG) and ultra low sulfur diesel fuel (ULSD). [Application; and Rules 62-210.200[Definitions-Potential to Emit (PTE)] and 62-4.070(3), F.A.C.]

CONTROL TECHNOLOGY

4. Wet Injection: The permittee shall install, adjust, operate, and maintain a water injection system to reduce NOx emissions from each SCCT. Prior to the initial emissions performance tests, the water injection system shall be adjusted to achieve the permitted NOx emissions standards. Thereafter, the water injection system shall be maintained and adjusted in accordance with the manufacturer's recommendations or determined best practices to minimize emissions. [Applicant request and Rule 62-4.070(3), F.A.C.]

5. Oxidation Catalyst: The permittee shall install, operate, and maintain an oxidation catalyst system to reduce CO and VOC emissions from each SCCT. The system shall be maintained and operated in accordance with the manufacturer's recommendations or determined best practices to minimize emissions. [Applicant request and Rule 62-4.070(3), F.A.C.]

PERFORMANCE REQUIREMENTS

6. Hours of Operation: SCCT 4A and SCCT 4B are allowed to operate in the peaking service mode for no more than 3,500 hr/calendar year each, including no more than 500 hr/calendar year each on ULSD. Any hour used to fire ULSD will decrease an hour that could have been used to fire NG. [Applicant request; and Rules 62-4.070(3), 62-210.200(Definitions-PTE) and 62-212.400(PSD), F.A.C.]

7. Permitted Capacity: The maximum heat input rate of each SCCT is 342.7 MMBtu per hour when firing NG or 302.7 MMBtu when firing ULSD [based on 100% load with evaporative cooling, 59° F ambient temperature, 52° F compressor inlet air temperature, and the higher heating value (HHV) of the fuel]. Heat input rates will vary depending upon turbine characteristics, ambient conditions and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Application and design; and Rules 62-4.070(3) and 62-210.200(Definitions-PTE), F.A.C.]

8. Authorized Fuels: Each CT is allowed to fire NG and ULSD. The NG shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet (2.0 gr S/100 scf). The ULSD shall contain a maximum sulfur content of 0.0015 %, by weight. [Rules 62-210.200(Definitions-PTE) and 62-212.400(PSD), F.A.C.]

9. Simple Cycle Mode: Each CT shall operate only in the simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and emission standards specified in this permit. For any request to convert these units to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel or quantity related to combined cycle conversion that may cause an increase in short or long-term emissions, the permittee shall submit a full PSD permit application complete with a proposed best available control technology (BACT) determination as if the SCCT peaking units had never been built. [Rules 62-210.200(Definitions-PTE) and 62-212.400(PSD), F.A.C.]

EMISSIONS AND TESTING REQUIREMENTS

10. Emission Standards: Emissions from each SCCT shall not exceed the following NSPS and State Implementation Plan (SIP) standards.

Pollutant	Fuel	Emission Standard [e]	Averaging Time	Compliance Method	Basis
NOx [a]	NG	25.0 ppmvd @ 15% oxygen (O_2) (NSPS) [f]	4-hr rolling avg [g]	CEMS	40 CFR 60.4320
		32.0 lb/hr/SCCT (SIP)	3 run avg.	Stack Test	Applicant requested Rule 62-4.070(3), F.A.C.
	ULSD	42.0 ppmvd @ 15% oxygen (O_2) (SIP)	4-hr rolling avg	CEMS	Applicant requested Rule 62-4.070(3), F.A.C.
		51.3 lb/hr/SCCT (SIP)	3 run avg.	Stack Test	
	NG and ULSD	25.0 ppmvd @ 15% oxygen (O_2) (NSPS) [f] or 42.0 ppmvd @ 15% oxygen (O_2) (SIP)	4-hr rolling avg [g]	CEMS	40 CFR 60.4325
CO [b]	NG	21.0 ppmvd @ 15% O_2 (SIP)	3-hr rolling avg	CEMS	Applicant requested Rule 62-4.070(3), F.A.C.
		9.1 lb/hr/SCCT (SIP)	3 run avg.	Stack Test	
	ULSD	5.1 ppmvd @ 15% O_2 (SIP)	3-hr rolling avg	CEMS	Applicant requested Rule 62-4.070(3), F.A.C.
		2.1 lb/hr/SCCT (SIP)	3 run avg.	Stack Test	
Visible Emissions [c]		10 % Opacity (SIP)	6-minute block	Visible Emissions Test	Applicant requested Rule 62-4.070(3), F.A.C.
PM [c]		NG: 2.0 gr S/100 scf (SIP) ULSD: 0.0015% S content, by wt (SIP)	N/A	Recordkeeping	Vendor data of analyses
SO_2 [d]	NG	NG: 2.0 gr S/100 scf (SIP)	N/A	Demonstration of fuel combusted and vendor data of analyses	Applicant requested
		0.90 lb/MWh/SCCT gross output [d] (NSPS)			40 CFR 60.4330(a)(1)
		or			
		0.060 lb/MMBtu/SCCT heat input [d] (NSPS)			40 CFR 60.4330(a)(2)
	ULSD	ULSD: 0.0015% S content, by wt (SIP)			Applicant requested
		0.90 lb/MWh/SCCT gross output [d] (NSPS)			40 CFR 60.4330(a)(1)
		or			
		0.060 lb/MMBtu/SCCT heat input [d] (NSPS)			40 CFR 60.4330(a)(2)

a. The permittee shall conduct initial and annual tests [Relative Accuracy Test Audit (RATA)] on each SCCT to demonstrate compliance with the short-term NOx emission limits [ppmvd @ 15% O_2 and lb/hr (mass emissions)] per fuel type. Thereafter, continuous compliance shall be demonstrated with the 4-hour rolling average NOx emission limits by data collected from the required continuous emissions monitoring system (CEMS). When firing ULSD, compliance with the SIP limit ensures compliance with the NSPS limit of 74 ppmvd @ 15% O_2. When firing both NG and ULSD, compliance with the NSPS limit is ensured by complying with either the NSPS limit, for NG, or the SIP limit, for ULSD, depending on the contribution of the fuels of the total heat input: if the total heat input contribution is equal to or greater than 50 percent from NG, you must meet the corresponding limit for a NG-fired turbine when you are burning that fuel; similarly, when your total heat input contribution is greater than 50 percent from ULSD, you must meet the corresponding limit for ULSD for the duration of the time that you burn that particular fuel.

b. The permittee shall conduct an initial test on each SCCT to demonstrate compliance with the short-term [ppmvd @ 15% O_2 and lb/hr (mass emissions)] CO emission limits per fuel type. Thereafter, continuous compliance shall be demonstrated with the 3-hour rolling average CO emission limits by data collected by the required CEMS. CO will be used as a surrogate for VOC emissions as a demonstration of good combustion.

c. The sulfur fuel specification combined with the efficient combustion design and operation of the turbines should minimize PM emissions (PM emissions are a surrogate for PM_{10} emissions) as well as visible emissions. No stack tests are required. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: Maximum expected PM/PM_{10} emissions from each turbine are approximately 2.5 and 7.5 lb/hr for NG and ULSD, respectively.}*

d. The fuel sulfur specifications effectively limit the potential emissions of SO_2 (and essentially sulfuric acid mist). For compliance purposes, the permittee elected to demonstrate that the fuel combusted will not exceed the potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input (see Appendix G of the permit). *{Permitting Note: Maximum expected SO_2 emissions from each turbine are approximately 1.9 lb/hr and 0.5 lb/hr for NG and ULSD, respectively.}*

e. The mass emission rate standards are based on a turbine inlet temperature condition of 59 °F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

f. 40 CFR 60, Subpart KKKK as described in 40 CFR 60.4320(a).

g. 40 CFR 60, Subpart KKKK as described in 40 CFR 60.4350(g).

{Permitting Note: In combination with the annual restriction on hours of operation, the above emissions standards effectively limit annual potential emissions from both gas turbines to: 16.5 tons/year of CO, 121.7 tons/year of NOx, 11.3 tons/year of PM/PM_{10}, 6.6 tons/year of SO_2, 0.8 tons/year of SAM, and 4.7 tons/year of VOC.}

[Applicant requested; Rules 62-4.070(3), 62-210.200(Definitions-PTE) and 62-212.400(PSD), F.A.C.; and 40 CFR 60, Subpart KKKK]

11. Unconfined Particulate Emissions: During the construction period, unconfined PM emissions shall be minimized by dust suppressing techniques such as covering, confining, or applying water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

12. Standard Testing Requirements: See Appendix D (Standard Testing Requirements) of this permit for notification, testing, recordkeeping and reporting requirements regarding a performance test. [Rules 62-204.800 and 62-297.100, F.A.C.; Appendix D of this permit; and 40 CFR 60, Appendix A]

13. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1-4	Methods for Determining Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content: These methods shall be performed as necessary to support other methods.
5	Method for Determining Particulate Matter Emissions
7E	Determination of NOx Emissions from Stationary Sources (Instrumental)
6 or 6C	Determination of SO_2 Emissions from Stationary Sources
8	Determination of SAM and SO_2 Emissions from Stationary Sources
9	Visual Determination of Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography *{Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}*
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxide Emissions Rates
20	Determination of NOx, SO_2, and Diluent Emissions from Stationary Combustion Turbines
25A	Determination of Total Gaseous Organic Concentrations Using a Flame Ionization Analyzer

The methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used for compliance testing unless prior written approval is received from the Administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to Rule 62-297.620, F.A.C. [Rule 62-204.800, F.A.C. and 40 CFR 60, Appendix A]

14. Testing Requirements: Initial and subsequent performance tests shall be conducted between 90% and 100% of permitted capacity in accordance with the requirements of Rule 62-297.310(2), F.A.C. [Rules 62-297.310(2) and (7)(a), F.A.C.; 40 CFR 60.8; and Appendix D of this permit]

15. Initial Compliance Demonstration: Initial compliance tests shall be conducted within 60 days after achieving the maximum production rate at which the units will be operated, but not later than 180 days after the initial startup. In accordance with the test methods specified in this permit, each turbine exhaust stack shall be tested for each fuel to demonstrate compliance with the emission limits for CO, NOx and visible emissions. For each test run (including visible emissions tests), CO and NOx emissions recorded by the required CEMS shall be reported. [Rule 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8; and Appendix D of this permit]

16. Annual Compliance Testing: During each federal fiscal year (October 1st to September 30th), annual compliance tests for visible emissions shall be conducted. For each visible emissions test, emissions of CO and NOx recorded by the CEMS shall also be reported. [Rules 62-297.310(7)(a) and (b), F.A.C. and Appendix D of this permit]

17. Initial and Subsequent Compliance Demonstration for NOx: See 40 CFR 60.4400 and 4405 in Appendix G (NSPS Subpart KKKK Requirements for Stationary Combustion Turbines) of this permit for the initial and subsequent compliance demonstration for NOx. [40 CFR 60.4400 and 60.4405; and Appendices A and G of this permit]

18. Initial and Subsequent Compliance Demonstration for Sulfur: See 40 CFR 60.4415 in Appendix G (NSPS Subpart KKKK Requirements for Stationary Combustion Turbines) of this permit for the initial and subsequent compliance demonstration for SO_2. A one-time compliance test on one CT shall be conducted for SO_2 mass emissions in order to satisfy compliance with the mass limit and the quality of the NG and ULSD. Afterwards, the use of NG and ULSD in accordance with the permit and 40 CFR 60.4415 will be used as a surrogate for SO_2 emissions. [40 CFR 60.4415; Appendices A and G of this permit; and Rule 62-4.070(3), F.A.C.]

19. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 3-hour rolling average CO emissions standards and with the 4-hour rolling average NOx emission standards based on data collected by the required CEMS. Within 45 days of conducting any RATA on a CEMS that represents the annual compliance test, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. If the RATA on a CEMS was not conducted as an annual compliance test, then the results can be submitted with the SIP Quarterly or Semiannual Report. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which also reduces emissions of PM. [Rules 62-4.070(3) and 62-297.310(7)(a) and (b), F.A.C.]

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

EXCESS EMISSIONS

{Permitting Note: Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

21. Definitions: Rule 62-210.200(Definitions), F.A.C., defines the following terms.
    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.
    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.
    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner

22. Excess Emissions Allowed - SIP. See Appendix C (Common Conditions) of this permit. [Rule 62-210.700(1), F.A.C. and Appendix C of this permit]

23. Excess Emissions Prohibited - SIP. See Appendix C (Common Conditions) of this permit. [Rule 62-210.700(4), F.A.C. and Appendix C of this permit]

24. Allowable SIP CO and NOx Data Exclusions: Provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions are minimized, CO and NOx CEMS data collected during periods of startup, shutdown and malfunction may be excluded from the 3-hr rolling average and 4-hr rolling average, respectively, compliance demonstrations only in accordance with the following requirements. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown and malfunction) may be excluded. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

a. *Startup*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 10 minutes of CEMS data shall be excluded for each gas turbine startup. For startups of less than 10 minutes in duration, only those minutes attributable to startup shall be excluded.

b. *Shutdown*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 10 minutes of CEMS data shall be excluded for each gas turbine shutdown. For shutdowns less than 10 minutes in duration, only those minutes attributable to shutdown shall be excluded.

c. *Malfunction*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than 120 minutes of CEMS data shall be excluded in a 24-hour period for each gas turbine due to malfunctions. Within one (1) working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data.

The permittee shall notify the Compliance Authority within one working day of discovering any emissions in excess of a CEMS standard subject to the specified averaging period. All such reasonably preventable emissions shall be included in any CEMS compliance determinations. All valid emissions data (including data collected during startup, shutdown and malfunction) shall be used to report annual emissions for the Annual Operating Report. [Rules 62-4.070(3), 62-210.200, 62-210.370(3) and 62-210.700, F.A.C.]

25. Excess Emissions NSPS - NOx: See 40 CFR 60.4350 and 4380 in Appendix G (NSPS Subpart KKKK Requirements for Stationary Combustion Turbines) of this permit. [40 CFR 60.4350 and 60.4380]

26. Excess Emissions NSPS - SO_2: See 40 CFR 60.4385 in Appendix G (NSPS Subpart KKKK Requirements for Stationary Combustion Turbines) of this permit. [40 CFR 60.4385

CONTINUOUS EMISSIONS MONITORING SYSTEMS (CEMS) REQUIREMENTS

27. CEMS: The permittee shall install, calibrate, maintain and operate the diluent CEMS to measure CO_2 emissions and CEMS to measure and record the emissions of CO and NOx from each gas turbine in a manner sufficient to demonstrate continuous compliance with the emission standards of this section. All continuous monitoring systems shall be installed and functioning within the required performance specification by the time of the initial performance tests.

    a. *NOx Monitor:* Each NOx monitor shall be certified pursuant to the specifications of 40 CFR 75. Quality assurance procedures shall conform to the requirements of 40 CFR 75. The annual and required Relative Accuracy Test Audit (RATA) tests required for the NOx monitor shall be performed using EPA Method 7E or 20 in 40 CFR 60, Appendix A.

    b. *CO Monitor:* Each CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The annual and required RATA tests required for the CO monitor shall be performed using EPA Method 10 in 40 CFR 60, Appendix A, and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

    c. *SO_2 Monitoring:* SO_2 monitoring will be in accordance with 40 CFR 75, Appendix D requirements (using sulfur content and fuel flow rates).

    d. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

[Rules 62-4.070(3) and 62-297.520, F.A.C.; 40 CFR 75; and Appendix E of this permit]

28. CEMS Data Requirements: The CEMS shall be installed, calibrated, maintained and operated in the gas turbine stacks to measure and record the emissions of CO and NOx in a manner sufficient to demonstrate compliance with the CEMS-based emission limits of this section. The CEMS shall express the results in units of ppmvd corrected to 15% oxygen. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable NOx standards of 40 CFR 60, Subpart KKKK, Table 1. The permittee shall be in compliance with the terms and conditions contained in Appendix E, Standard Continuous Monitoring Requirements, of this permit. [Rule 62-4.070(3), F.A.C. and Appendix E of this permit]

29. CEMS Annual Emissions Requirement: The owner or operator shall use data from the NOx and CO CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rule 62-210.370(3), F.A.C., Annual Operating Report. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit. [Rules 62-210.200(Definitions) and 62-210.370(3), F.A.C.]

REPORTING AND RECORDKEEPING REQUIREMENTS

30. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. [Rule 62-297.310(8), F.A.C. and Appendix D of this permit]

31. Monitoring of Capacity: The permittee shall monitor and record the heat input of each CT on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). This shall be achieved through monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75, Appendix D, and recording the data using a monitoring component of the CEMS required above. [Rule 62-4.070(3), F.A.C. and Appendix E of this permit]

32. Monthly Operations Summary: By the 15th calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the combustion turbine for the previous month of operation: fuel consumption, hours of operation and the updated calendar year totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. [Rule 62-4.070(3), F.A.C.]

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

    a. *Natural Gas Sulfur Limit*: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. A representative sample shall be collected using ASTM D5287. Methods for determining the sulfur content of the natural gas shall be ASTM methods D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gaseous Processors Association Standard 2377, or more recent versions, or through provisions listed in 40 CFR 60, Subpart KKKK that allows alternate NG fuel sulfur monitoring.

    b. *ULSD Fuel Sulfur Limit*: Compliance with the fuel sulfur limit for ULSD fuel shall be demonstrated by keeping each bill of lading report obtained from the vendor indicating the sulfur content, percent by weight, of the ULSD fuel being delivered. A representative sample shall be collected using ASTM D5287. Methods for determining the sulfur content of the ULSD fuel shall be ASTM methods D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gaseous Processors Association

Standard 2377, or more recent versions, or through provisions listed in 40 CFR 60, Subpart KKKK that allows alternate sulfur monitoring for ULSD.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 60.4415. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.; 40 CFR 60.4415; and Appendix G of this permit]

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

35. CEMS RATA Reports: At least 15 days prior to conducting any RATA on a CEMS, the permittee shall notify the Compliance Authority of the schedule (letter, email, fax, or phone call). A summary of the RATA reports shall be provided upon written request of the Compliance Authority and in the SIP Excess Emissions Report as specified in specific condition 36. [Rule 62-4.070(3), F.A.C.]

36. Excess Emissions Reporting:

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

   b. *SIP Excess Emissions Report*: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority of the following for each gas turbine using the NSPS format in 40 CFR 60.7(c), Subpart A: a summary of the 4-hour rolling average NOx compliance periods for the quarter; a summary of the 3-hour rolling average CO compliance periods for the quarter; a summary of NOx and CO data excluded for the quarter; a summary of any RATA tests performed during the quarter; and a summary of the CEMS systems monitor availability for the quarter.

      (1) If four consecutive quarterly reports demonstrate compliance with the CEMS-based emissions standards, the reporting frequency may be reduced to semiannual reporting. As part of the fourth consecutive satisfactory quarterly report, the permittee shall provide written notification of its intent to reduce the reporting frequency to a semiannual basis. The notification shall include a statement that the units were in full compliance during the four consecutive quarters and that reporting will be reduced to a semiannual basis. Semiannual reports shall include above information required for each quarter in the semiannual period. The permittee shall continue to comply with all other record keeping and monitoring provisions.

      (2) If reports are being submitted on a semiannual basis and a unit is not in compliance with the CEMS-based emissions standards, the permittee shall immediately (within one day of detection) notify the Compliance Authority of the compliance status and reestablish quarterly reporting beginning with the current quarter. If compliance is reestablished for four consecutive quarters, semiannual reporting may resume as specified above.

   c. *NSPS Reporting*: For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under 40 CFR 60, Subpart KKKK, the owner or operator must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR

60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown and malfunction.

{Note: If there are no periods of excess emissions as defined in 40 CFR 60, Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semiannual Report.}

[Rules 62-4.070(3), 62-4.130, 62-204.800 and 62-210.700(6), F.A.C.; and 40 CFR 60.7 and 60.4375]

37. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility in accordance with Rule 62-210.370, F.A.C., and Appendix C (Common Conditions) of this permit. Annual operating reports shall be submitted to the Compliance Authority by May 1, 2009, for calendar year 2008, and April 1st thereafter. [Rule 62-210.370(3), F.A.C.]

CONTENTS

CITATION FORMATS AND GLOSSARY OF COMMON TERMS

CITATION FORMATS

The following illustrate the formats used in the permit to identify applicable requirements from permits and regulations.

Old Permit Numbers

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

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

New Permit Numbers

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

Where: "099" represents the specific county ID number in which the project is located

"2222" represents the specific facility ID number for that county

"001" identifies the specific permit project number

"AC" identifies the permit as an air construction permit

"AF" identifies the permit as a minor source federally enforceable state operation permit

"AO" identifies the permit as a minor source air operation permit

"AV" identifies the permit as a major Title V air operation permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the preconstruction review requirements of the Prevention of Significant Deterioration of Air Quality

"FL" means that the permit was issued by the State of Florida

"317" identifies the specific permit project number

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

GLOSSARY OF COMMON TERMS

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

ARMS: Air Resource Management System (Department's database)

BACT: best available control technology

Btu: British thermal units

CAM: compliance assurance monitoring

CEMS: continuous emissions monitoring system

cfm: cubic feet per minute

CFR: Code of Federal Regulations

CO: carbon monoxide

CO_2: carbon dioxide

COMS: continuous opacity monitoring system

DEP: Department of Environmental Protection

Department: Department of Environmental Protection

dscfm: dry standard cubic feet per minute

EPA: Environmental Protection Agency

ESP: electrostatic precipitator (control system for reducing particulate matter)

EU: emissions unit

F.A.C.: Florida Administrative Code

F.D.: forced draft

F.S.: Florida Statutes

FGR: flue gas recirculation

Fl: fluoride

ft^2: square feet

ft^3: cubic feet

gpm: gallons per minute

gr: grains

gr/dscf: grains per dry standard cubic feet

HAP: hazardous air pollutant

Hg: mercury

HHV: higher heating value

I.D.: induced draft

ID: identification

kPa: kilopascals

lb: pound

MACT: maximum achievable technology

MMBtu: million British thermal units

MSDS: material safety data sheets

MW: megawatt

NESHAP: National Emissions Standards for Hazardous Air Pollutants

NOx: nitrogen oxides

NSPS: New Source Performance Standards

O&M: operation and maintenance

O_2: oxygen

Pb: lead

PM: particulate matter

PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less

PSD: prevention of significant deterioration

psi: pounds per square inch

PTE: potential to emit

RACT: reasonably available control technology

RATA: relative accuracy test audit

SAM: sulfuric acid mist

scf: standard cubic feet

scfm: standard cubic feet per minute

SIC: standard industrial classification code

SNCR: selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)

SO_2: sulfur dioxide

TPH: tons per hour

TPY: tons per year

UTM: Universal Transverse Mercator coordinate system

VE: visible emissions

VOC: volatile organic compounds

GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the F.S. or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, F.S.. Such evidence

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

10. The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.
11. This permit is transferable only upon Department approval in accordance with Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology (applicable);
    b. Determination of Prevention of Significant Deterioration (applicable); and
    c. Compliance with New Source Performance Standards (applicable).
14. The permittee shall comply with the following:
    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
    c. Records of monitoring information shall include:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

COMMON CONDITIONS

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

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(Definitions), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

{Permitting Note: Rule 62-210.700 (Excess Emissions), F.A.C., cannot vary any NSPS or NESHAP provision.}

RECORDS AND REPORTS

10. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]
11. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(3), F.A.C.]

STANDARD TESTING REQUIREMENTS

Unless otherwise specified in the permit, the following testing requirements apply to all emissions units at the facility.

COMPLIANCE TESTING REQUIREMENTS

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

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

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

4. Applicable Test Procedures

   a. *Required Sampling Time.*

      (1) Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

      (2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

         (a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

         (b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

         (c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

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

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

d. *Allowed Modification to EPA Method 5.* When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

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

5. Determination of Process Variables

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

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

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

6. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

a. *Permanent Test Facilities.* The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

b. *Temporary Test Facilities.* The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department or its designee elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department or its designee and remain on the emissions unit until the test is completed.

c. *Sampling Ports.*

(1) All sampling ports shall have a minimum inside diameter of 3 inches.

(2) The ports shall be capable of being sealed when not in use.

(3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

(4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

(5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms.*

(1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

(2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

(3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

(4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform.*

(1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

(2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power.*

(1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

(2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

(1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

(a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

(b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

(c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

(2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.

(3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

[Rule 62-297.310(6), F.A.C.]

7. Frequency of Compliance Tests: The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

a. *General Compliance Testing.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

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

   (a) Did not operate; or

   (b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,

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

   (a) Visible emissions, if there is an applicable standard;

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

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

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9. The owner or operator shall notify the Department or its designee, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

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

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

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

RECORDS AND REPORTS

8. Test Reports:

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department or its designee on the results of each such test.

b. The required test report shall be filed with the Department or its designee as soon as practical but no later than 45 days after the last sampling run of each test is completed.

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

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.

15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

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

The new SCCT peaking units SCCT 4A and SCCT 4B (EU-041 and 042, respectively) are subject to the following requirements for the new continuous emissions monitoring systems (CEMS) required for CO and NOx emissions and CO_2 for diluent.

CEMS OPERATION PLAN

1. CEMS Operation Plan: The permittee shall create and implement a plan for the proper installation, calibration, maintenance, and operation of each CEMS required by this permit. The permittee shall submit the CEMS Operation Plan to the Bureau of Air Monitoring and Mobile Sources for approval prior to CEMS installation. The CEMS Operation Plan shall become effective 60 days after submittal or upon its approval. If the CEMS Operation Plan is not approved, the permittee shall submit a new or revised plan for approval. *{Permitting Note: The Department maintains both guidelines for developing a CEMS Operation Plan and example language that can be used as the basis for the facility-wide plan required by this permit. Contact the Emissions Monitoring Section of the Bureau of Air Monitoring and Mobile Sources at 850/488-0114.}* [Rule 62-4.070(3), F.A.C.]

MONITORS, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. Span Values and Dual Range Monitors: The permittee shall set appropriate span values for the CEMS based on the emissions standards and range of operation. If necessary, the permittee shall install dual range monitors in accordance with the CEMS Operation Plan. [Rule 62-4.070(3), F.A.C.]

3. Diluent Monitor: If required by permit to correct the CEMS output to the oxygen concentrations specified in the applicable emissions standard, the permittee shall either install an oxygen monitor or install a CO_2 monitor and use an appropriate F-Factor computational approach. [Rule 62-4.070(3), F.A.C.]

4. Moisture Correction: If necessary, the permittee shall install a system to determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). [Rule 62-4.070(3), F.A.C.]

5. Continuous Flow Monitor: For compliance with mass emission flow rate standards, the permittee shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 6. Alternatively, the permittee may install a fuel flow monitor and use an appropriate F-Factor computational approach to calculate stack exhaust flow rate. *{Permitting Note: The CEMS Operation Plan will contain additional details and procedures for CEMS installation.}* [Rule 62-4.070(3), F.A.C.]

6. Performance Specifications: The permittee shall evaluate the "acceptability" of each CEMS by conducting the appropriate performance specification. CEMS determined to be "unacceptable" shall not be considered "installed" for purposes of meeting the timelines of this permit. For CO monitors, the permittee shall conduct Performance Specification 4 of 40 CFR 60, Appendix B. For NOx monitors, the permittee shall conduct Performance Specification 2 of 40 CFR 60, Appendix B, or the applicable CEMS certification procedures of 40 CFR 75, Appendix A, Section 6. [Rule 62-4.070(3), F.A.C.; 40 CFR 60; and 40 CFR 75]

7. Quality Assurance: The permittee shall follow the quality assurance procedures of 40 CFR 60, Appendix F. For NOx, the permittee may follow the applicable quality assurance requirements of 40 CFR 75, Appendix B. For CO, the required relative accuracy test audit (RATA) tests shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. For NOx, the RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR 60. [Rule 62-4.070(3), F.A.C.; 40 CFR 60; and 40 CFR 75]

CALCULATION APPROACH FOR SIP COMPLIANCE

8. CEMS for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the permittee shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit. [Rule 62-4.070(3), F.A.C.]

9. CEMS Data: Each CEMS shall monitor and record emissions during all operations and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. Unless otherwise specified in this permit, all data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs,

calibration checks, zero adjustments, and span adjustments. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. [Rule 62-4.070(3), F.A.C.]

10. Operating Hours and Operating Days: For purposes of this Appendix, the following definitions shall apply. An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit. [Rule 62-4.070(3), F.A.C.]

11. Valid Hourly Averages: Each CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

    a. Hours that are not operating hours are not valid hours.

    b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

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

12. Calculation Approaches: The permittee shall implement the calculation approach specified by this permit for each CEMS, as follows:

    a. *Daily Averages*:

    b. *Rolling 30-day Average*.

    c. *4-Hour Rolling Average (NO_X)*: Compliance with the 4-hour rolling average shall be determined after each operating hour by calculating and recording the arithmetic average of all valid hourly averages for the previous 4 operating hours (compliance period).

    d. *3-Hour Rolling Average (CO)*: Compliance with the 3-hour rolling average shall be determined after each operating hour by calculating and recording the arithmetic average of all valid hourly averages for the previous 3 operating hours (compliance period).

    e. *Rolling 12*-month Totals:

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

13. Minimum Valid Hours: At least one valid hourly average shall be used to calculate the emissions over any averaging period specified by this permit. One valid hourly average shall be sufficient to calculate the emissions over any averaging period. [Rule 62-4.070(3), F.A.C.]

MONITOR AVAILABILITY

14. Monitor Availability: Monitor availability shall be calculated on a quarterly basis for each emission unit as the number of valid hourly averages obtained by the CEMS, divided by the number of operating hours, times 100%. The monitor availability calculation shall not include periods of time where the monitor was functioning properly, but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit, or relative accuracy audits (RAA). Monitor availability for each CEMS shall be 95% or

greater in any calendar quarter. Monitor availability shall be reported in the quarterly excess emissions report. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit. [Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

15. Definitions:

    a. *Excess Emissions* (under the Florida SIP) are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction.

    b. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

    c. *Shutdown* means the cessation of the operation of an emissions unit for any purpose.

    d. *Malfunction* means any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

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

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

17. Data Exclusion Procedures for SIP Compliance: As per the procedures in this condition, limited amounts of CO and NO_X CEMS emissions data may be excluded from the corresponding compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

    a. *Excess Emissions.* For purposes of SIP-based permit limits, excess emissions data collected during periods of startup and shutdown may be excluded from compliance calculations as allowed by the permit standards.

    b. *Limiting Data Exclusion.* If the compliance calculation using all valid CEMS emission data (as defined in this Appendix) indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

    c. *Event Driven Exclusion.* The excess emissions must occur due to an underlying event (startup or shutdown). If there is no underlying event, then no data may be excluded.

    d. *Continuous Exclusion.* Data shall be excluded on a continuous basis per event. Data from discontinuous periods shall not be excluded for the same underlying event.

    e. *Reporting Excluded Data.* These procedures for excluding SIP-based excess emissions from compliance calculations are not necessarily the same procedures used for "excess emissions" as defined by federal rules. Semiannual reports required by this permit shall indicate the duration of data excluded from SIP compliance calculations as well as the number of excess emissions as defined in the applicable federal rules.

    {Permitting Note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.} [Rule 62-210.700(4), F.A.C.]

18. Notification Requirements: The permittee shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate non-compliance for a given averaging period. [Rule 62-4.070(3), F.A.C.]

CALCULATING AND REPORTING ANNUAL EMISSIONS

19. CEMS for Calculating Annual Emissions: As defined by this Appendix, all valid data shall be used when calculating annual emissions.

    a. Annual emissions shall include data collected during startup, shutdown, and malfunction periods.

    b. Annual emissions shall include data collected during periods when the emission unit is not operating, but emissions are being generated (for example, firing fuel to warm up a process for some period of time prior to the emission unit's "official" startup).

    c. Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit, or RAA. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

    d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

20. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average that begins at the top of each hour. For each hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the permittee shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hour block average.

21. Emissions Calculation: Annual emissions shall be calculated as the sum of all valid emissions occurring during the year.

22. Reporting Annual Emissions: The permittee shall use data from each required CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rules 62-210.370(3) and 62-212.300(1)(e), F.A.C. [Rule 62-4.070(3), F.A.C.]

NSPS SUBPART A, GENERAL CONDITIONS

Emissions units subject to a New Source Performance Standards of 40 CFR 60 are also subject to the applicable requirements of Subpart A, General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

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

NSPS SUBPART KKKK, REQUIREMENTS FOR STATIONARY COMBUSTION TURBINES

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoûles (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part.

§ 60.4310 What types of operations are exempt from these standards of performance?

(a) Not applicable (NA)

(b) NA

(c) NA

(d) NA

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NOx) and sulfur dioxide (SO_2).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NOx)?

(a) You must meet the emission limits for NOx specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NOx.

§ 60.4325 What emission limits must I meet for NOx if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1) or (a)(2) of this section.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

(b) NA.

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) NA.

Monitoring

§ 60.4335 How do I demonstrate compliance for NOx if I use water or steam injection?

(a) If you are using water or steam injection to control NOx emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NOx monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NOx emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu).

(2) NA.

(3) NA.

(4) NA.

§ 60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?

(a) NA.

(b) NA.

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NOx CEMS is chosen:

(a) Each NOx diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NOx diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NOx monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NOx emission rate for the hour.

(c) Each fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flow meters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NOx and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOx emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NOx concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NOx diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_X)_h * (HI)_h}{P} \qquad (Eq. 1)$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flow meter(s), *e.g.* , calculated using Equation D–15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) NA.

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) NA.

(b) NA.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel? NA.

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.* , flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§ 60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§ 60.4380 How are excess emissions and monitor downtime defined for NOx?

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NOx control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour rolling average NOx emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4- hour rolling average NOx emission rate" is the arithmetic average of the average NOx emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NOx emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NOx emission rate is obtained for at least 3 of the 4 hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NOx concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) NA.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel obtained using daily sampling, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine? NA.

§ 60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NOx?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NOx performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) For each test run:

(ii) Measure the NOx and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flow meter (or flow meters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NOx emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NOx emission rate in lb/MWh.

(2) Sampling traverse points for NOx and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NOx and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NOx concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5 ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NOx concentration during the stratification test; or

(B) For turbines with a NOx standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NOx concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3 ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points.

(C) NA.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) NA.

(3) If water or steam injection is used to control NOx with no additional post-combustion NOx control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NOx emissions limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NOx emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NO_X-diluent CEMS?

If you elect to install and certify a NOx-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NOx emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NOx emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters? NA.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17).

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

(2) NA.

(3) NA.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

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

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Excess emissions means a specified averaging period over which either (1) the NOx emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Table 1 to Subpart KKKK of Part 60-Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NOx emission standard
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh)

TECO

TAMPA ELECTRIC

RECEIVED

NOV 26 2008

BUREAU OF AIR REGULATION

November 25, 2008

Ms. Trina Vielhauer, Bureau Chief
Bureau of Air Regulation
Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5500
Tallahassee, Florida 32399-2400

Via FedEx
Airbill No. 7971 3878 4456

Re: Tampa Electric Company
Air Construction Permit Issuance
Proof of Publication of the Intent to Issue
DEP File No. 0570039-040-AC

Dear Trina:

Pursuant to Rule 62-110.106(5), F.A.C., enclosed is the proof of publication of the Notice of Intent to Issue the Tampa Electric Company Big Bend Station Air Construction Permit concerning Big Bend Station Two Simple Cycle Combustion Turbines – Generator Peaker Project. This notice was published in the legal section of the Tampa Tribune on November 21, 2008.

Thank you for your attention to this matter. If you have any concerns or questions feel free to contact me or Thuy Nguyen at (813) 228-4654.

Sincerely,

Byron T. Burrows, P.E.
Manager - Air Programs
Environmental, Health & Safety

EHS\rlk\ATN108

Enclosure

c/enc: Ms. Mara G. Nasca – FDEP, SW District
Mr. Bruce Mitchell – FDEP, Tallahassee
Ms. Diana Lee - EPCHC

Legal Notices

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation
Project No. 0570039-040-AC
Tampa Electric Company - Big Bend Station
Hillsborough County, Florida

Applicant: The applicant for this project is the Tampa Electric Company. The applicant's authorized representative and mailing address is: Mr. Paul L. Carpinone, Director, Environmental Health and Safety, Tampa Electric Company, Post Office 111, Tampa, Florida 33601-0111.

Facility Location: Tampa Electric Company operates an existing electric utility, the Big Bend Station (Big Bend), located at 13031 Wyandotte Road in Apollo Beach, Hillsborough County, Florida.

Project: The proposed project is to construct two simple cycle combustion turbines (SCCT), with one common electrical generator, and one emergency reciprocating internal combustion engine (RICE)-generator set at the existing Big Bend facility. SCCT 4A and SCCT 4B will be coupled to one common generator having a nominal gross generation capacity of 62 megawatts (MW). For each SCCT, the applicant proposes to fire pipeline-quality natural gas (NG) and ultra low sulfur diesel fuel (ULSD) while operating in the simple cycle mode. The NG shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet and the ULSD shall contain no more than 0.0015 percent sulfur content, by weight. The hours of operation are limited to 3,500 per SCCT per year while firing NG and 500 per SCCT per year while firing ULSD (any hour used to fire ULSD fuel will decrease an hour that could have been used to fire natural gas). Excluding emergency conditions, the RICE-generator set will only be operated for approximately 2 hours per week (100 hr/yr) each for routine testing and maintenance purposes and will fire only ULSD.

The project is not subject to the rules for the Prevention of Significant Deterioration (PSD) at Rule 62-212.400, Florida Administrative Code (F.A.C.), because there will not be significant net emissions increases of any criteria pollutant. For nitrogen oxides (NOx), creditable emission decreases from the permanent shutdown of the existing combustion turbines Nos. 1, 2 and 3 were used to net out of PSD new source review requirements at Rule 62-212.400, F.A.C. Therefore, the project is considered a minor modification to a major facility. An air quality impact analysis was not required.

An oxidation catalyst will be installed on each SCCT to reduce the emissions of carbon monoxide (CO) and volatile organic compounds (VOC). The use of low sulfur fuels, essentially inherently clean fuels, will minimize the emissions of sulfur dioxide (SO2), sulfuric acid mist (SAM), particulate matter (PM) and PM with an aerodynamic diameter equal to or less than 10 microns (PM10). Water injection will be used on each SCCT to minimize the emissions of NOx.

Each SCCT will be subject to the allowable NOx and SO2 emission limitations given in Title 40, Code of Federal Regulations, Part 60 (40 CFR 60), Subpart KKKK - Standards of Performance for Stationary Combustion Turbines that Commence Construction after February 18, 2005; however, for NOx when firing ULSD, the applicant requested a more stringent limit than what is allowed by the subpart.

The RICE-generator set is not subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR 63, Subpart ZZZZ, for Stationary RICE, because the potential emissions of hazardous air pollutants are less than major for the project; however, the RICE-generator set is entitled to the generic emissions unit exemption at Rule 62-210.300(3)(b)1., F.A.C., One or More Emergency Generators Located Within a Single Facility.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210 and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida 32301. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. In addition, electronic copies of these documents are available on the following web site:
www.dep.state.fl.us/air/eproducts/apds/default.asp.

The Tampa Tribune

Published Daily

Tampa, Hillsborough County, Florida

State of Florida }
County of Hillsborough } SS.

Before the undersigned authority personally appeared C. Pugh , who on oath says that she is the Advertising Billing Supervisor of The Tampa Tribune, a daily newspaper published at Tampa in Hillsborough County, Florida; that the attached copy of the

Legal Ads IN THE Tampa Tribune

In the matter of Legal Notices

was published in said newspaper in the issues of

11/21/2008

Affiant further says that the said The Tampa Tribune is a newspaper published at Tampa in said Hillsborough County, Florida, and that the said newspaper has heretofore been continuously published in said Hillsborough County, Florida, each day and has been entered as second class mail matter at the post office in Tampa, in said Hillsborough County, Florida for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, this advertisement for publication in the said newspaper.

____

Sworn to and subscribed by me, this 21 day of November, A.D. 2008

Personally Known ✓ or Produced Identification ______
Type of Identification Produced ____________

NOTARY PUBLIC - STATE OF FLORIDA
Ana Maria Hodel
Commission #DD551367
Expires: MAY 11, 2010
WWW.AARONNOTARY.com

____

1184763 -- TAMPA ELECTRIC COMPANY

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S., or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of 14 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 14-day period. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address and telephone number of the petitioner; the name address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial rights will be affected by the agency determination; (c) A statement of when and how the petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available for this proceeding.

9785 11/21/08

Livingston, Sylvia

From: Burrows, Byron T. [BTBurrows@tecoenergy.com]
Sent: Wednesday, December 10, 2008 4:37 PM
To: Livingston, Sylvia
Subject: Re: TECO - BIG BEND STATION; 0570039-040-AC

I am able to open docs. Thanks.
From Blackberry
Byron Burrows
Mobile: 813.230.3445

From: Livingston, Sylvia
To: Carpinone, Paul L.; Lukcic, David M.; Burrows, Byron T.; Nguyen, Andrew T.
Cc: tdavis@ectinc.com ; campbell@epchc.org ; Lee@epchc.org ; Zhu@epchc.org ; Gibson, Victoria ; Arif, Syed ; Mitchell, Bruce ; Walker, Elizabeth (AIR)
Sent: Wed Dec 10 16:17:29 2008
Subject: TECO - BIG BEND STATION; 0570039-040-AC

Dear Sir/ Madam:
Attached is the official **Notice of Final Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send". **We must receive verification that you are able to access the documents.** Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0570039.040.AC.F_pdf.zip

Owner/Company Name: TAMPA ELECTRIC COMPANY
Facility Name: BIG BEND STATION
Project Number: 0570039-040-AC
Permit Status: FINAL
Permit Activity: CONSTRUCTION
Facility County: HILLSBOROUGH
Processor: Bruce Mitchell

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/eproducts/apds/default.asp .

Permit project documents are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation at (850)488-0114.

<<0570039-040-AC_Signatures.pdf>>

Sylvia Livingston
Bureau of Air Regulation

Livingston, Sylvia

From: Tom Davis [tdavis@ectinc.com]
Sent: Wednesday, December 10, 2008 4:28 PM
To: Livingston, Sylvia
Subject: RE: TECO - BIG BEND STATION; 0570039-040-AC

Sylvia,

I have received and can view the documents provided.

Thanks.

From: Livingston, Sylvia [mailto:Sylvia.Livingston@dep.state.fl.us]
Sent: Wednesday, December 10, 2008 4:17 PM
To: plcarpinone@tecoenergy.com; dmlukcic@tecoenergy.com; btburrows@tecoenergy.com; atnguyen@tecoenergy.com
Cc: tdavis@ectinc.com; campbell@epchc.org; Lee@epchc.org; Zhu@epchc.org; Gibson, Victoria; Arif, Syed; Mitchell, Bruce; Walker, Elizabeth \(AIR\)
Subject: TECO - BIG BEND STATION; 0570039-040-AC

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<<0570039-040-AC_Signatures.pdf>>

Sylvia Livingston

Livingston, Sylvia

From: Lukcic, David M. [DMLukcic@tecoenergy.com]
To: Livingston, Sylvia
Sent: Wednesday, December 10, 2008 4:19 PM
Subject: Read: TECO - BIG BEND STATION; 0570039-040-AC

Your message

To: DMLukcic@tecoenergy.com
Subject:

was read on 12/10/2008 4:19 PM.

Livingston, Sylvia

From: Nguyen, Andrew T. [atnguyen@tecoenergy.com]
Sent: Wednesday, January 07, 2009 1:45 PM
To: Livingston, Sylvia
Subject: RE: TECO - BIG BEND STATION; 0570039-040-AC

Dear Sylvia,

Thank you for the reminder. This email is to confirm that TECO has received the subject project on December 10, 2008.

Take care,

Andrew (Thuy) Nguyen
Senior Engineer
EHS - Air Programs
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601-0111
Office: 813-228-4654
Fax: 813-228-1308
Cell: 813-309-1341
atnguyen@tecoenergy.com

From: Livingston, Sylvia [mailto:Sylvia.Livingston@dep.state.fl.us]
Sent: Tuesday, January 06, 2009 11:48 AM
To: Nguyen, Andrew T.
Subject: FW: TECO - BIG BEND STATION; 0570039-040-AC

Hi Andrew,

I am going through email responses and noticed that I didn't have one from you or Paul Carpinone. Could you find the original email and send me a confirmation for this one?

Thanks,

Sylvia Livingston

Bureau of Air Regulation

Division of Air Resource Management (DARM)

850/921-9506

sylvia.livingston@dep.state.fl.us

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Michael W. Sole is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few *minutes to comment on the quality of service you received. Simply click on this link to the DEP Customer Survey. Thank you in advance for completing the survey.*

From: Livingston, Sylvia
Sent: Wednesday, December 10, 2008 4:17 PM
To: 'plcarpinone@tecoenergy.com'; 'dmlukcic@tecoenergy.com'; 'btburrows@tecoenergy.com'; 'atnguyen@tecoenergy.com'
Cc: 'tdavis@ectinc.com'; 'campbell@epchc.org'; 'Lee@epchc.org'; 'Zhu@epchc.org'; Gibson, Victoria; Arif, Syed; Mitchell, Bruce; Walker, Elizabeth (AIR)
Subject: TECO - BIG BEND STATION; 0570039-040-AC

Dear Sir/ Madam:

Attached is the official **Notice of Final Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send". **We must receive verification that you are able to access the documents.** Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

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Owner/Company Name: TAMPA ELECTRIC COMPANY

Facility Name: BIG BEND STATION

Project Number: 0570039-040-AC

Permit Status: FINAL

Permit Activity: CONSTRUCTION

Facility County: HILLSBOROUGH

Processor: Bruce Mitchell

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Permit project documents are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation at (850)488-0114.

<<0570039-040-AC_Signatures.pdf>>

Sylvia Livingston

Bureau of Air Regulation

Division of Air Resource Management (DARM)

850/921-9506

sylvia.livingston@dep.state.fl.us

Livingston, Sylvia

From:	Livingston, Sylvia
Sent:	Monday, September 08, 2008 10:30 AM
To:	'Forney.Kathleen@epamail.epa.gov'
Cc:	Nasca, Mara; Sterling Woodard ('Sterling Woodard (E-mail)'); Mitchell, Bruce; Walker, Elizabeth (AIR)
Subject:	TECO - Big Bend Station (0570039-040-AC)

A new **Permit Application** has been received in Florida and is currently under review.

Link to Permit Application Documents:
http://arm-permit2k.dep.state.fl.us/psd/0570039/000030B3.pdf

ARMS PA Project ID:	0570039-040-AC

Facility Name:	TECO - Big Bend Station
Florida County:	Hillsborough
Project Description:	INSTALL UNIT 4 SCCT
Permit Application Processor:	Bruce Mitchell
Processor Phone:	(850)413-9198
Processor Email Address:	Bruce.Mitchell@dep.state.fl.us

Or, Search for other Air Permit Documents on Florida's Air Permit Documents Search.

Please direct any questions regarding this permit application to the permit application processor. If you have any problems accessing these documents please let me know.

Thanks,

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-0771

Livingston, Sylvia

From: Burrows, Byron T. [BTBurrows@tecoenergy.com]
Sent: Wednesday, November 19, 2008 6:29 PM
To: Livingston, Sylvia
Subject: RE: TECO- BIG BEND STATION; 0570039-040-AC

I can view the attached document. Thanks!
Byron

From: Livingston, Sylvia [mailto:Sylvia.Livingston@dep.state.fl.us]
Sent: Wednesday, November 19, 2008 1:27 PM
To: Carpinone, Paul L.; Lukcic, David M.; Burrows, Byron T.; Nguyen, Andrew T.
Cc: tdavis@ectinc.com; campbell@epchc.org; Lee@epchc.org; Zhu@epchc.org; Gibson, Victoria; Arif, Syed; Mitchell, Bruce; Walker, Elizabeth (AIR)
Subject: TECO- BIG BEND STATION; 0570039-040-AC

Dear Sir/ Madam:
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Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0570039.040.AC.D_pdf.zip

Owner/Company Name: TAMPA ELECTRIC COMPANY
Facility Name: BIG BEND STATION
Project Number: 0570039-040-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: HILLSBOROUGH
Processor: Syed Arif & Cleve Holladay

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<<0570039-040-AC_Intent.pdf>>

Sylvia Livingston

Livingston, Sylvia

From: Nguyen, Andrew T. [atnguyen@tecoenergy.com]
Sent: Wednesday, November 19, 2008 1:42 PM
To: Livingston, Sylvia
Cc: Carpinone, Paul L.; Lukcic, David M.; Burrows, Byron T.; Bishop, Ron D.
Subject: RE: TECO- BIG BEND STATION; 0570039-040-AC

Dear Sylvia,

As per our conversation, I am replying to this email for your receipt. Per your request, I copied all names that were on the "sent to" list on your email and also include Mr. Ron Bishop (the RO of the Big Bend Power Station). This action is to conform with the Department's email receipt request policy.

Thanks,

Andrew (Thuy) Nguyen
Senior Engineer
EHS - Air Programs
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601-0111
Office: 813-228-4654
Fax: 813-228-1308
Cell: 813-309-1341
atnguyen@tecoenergy.com

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Sent: Wednesday, November 19, 2008 1:27 PM
To: Carpinone, Paul L.; Lukcic, David M.; Burrows, Byron T.; Nguyen, Andrew T.
Cc: tdavis@ectinc.com; campbell@epchc.org; Lee@epchc.org; Zhu@epchc.org; Gibson, Victoria; Arif, Syed; Mitchell, Bruce; Walker, Elizabeth (AIR)
Subject: TECO- BIG BEND STATION; 0570039-040-AC

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http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0570039.040.AC.D_pdf.zip

Owner/Company Name: TAMPA ELECTRIC COMPANY
Facility Name: BIG BEND STATION
Project Number: 0570039-040-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: HILLSBOROUGH
Processor: Syed Arif & Cleve Holladay

Livingston, Sylvia

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Sent: Wednesday, November 19, 2008 1:42 PM
To: Livingston, Sylvia
Cc: Carpinone, Paul L.; Lukcic, David M.; Burrows, Byron T.; Bishop, Ron D.
Subject: RE: TECO- BIG BEND STATION; 0570039-040-AC

Dear Sylvia,

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Andrew (Thuy) Nguyen
Senior Engineer
EHS - Air Programs
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P.O. Box 111
Tampa, FL 33601-0111
Office: 813-228-4654
Fax: 813-228-1308
Cell: 813-309-1341
atnguyen@tecoenergy.com

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Sent: Wednesday, November 19, 2008 1:27 PM
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Subject: TECO- BIG BEND STATION; 0570039-040-AC

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Facility Name: BIG BEND STATION
Project Number: 0570039-040-AC
Permit Status: DRAFT
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Facility County: HILLSBOROUGH
Processor: Syed Arif & Cleve Holladay

Livingston, Sylvia

From: Livingston, Sylvia
Sent: Monday, September 08, 2008 10:30 AM
To: 'Forney.Kathleen@epamail.epa.gov'
Cc: Nasca, Mara; Sterling Woodard ('Sterling Woodard (E-mail)'); Mitchell, Bruce; Walker, Elizabeth (AIR)
Subject: TECO - Big Bend Station (0570039-040-AC)

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ARMS PA Project ID:	0570039-040-AC

Facility Name:	TECO - Big Bend Station
Florida County:	Hillsborough
Project Description:	INSTALL UNIT 4 SCCT
Permit Application Processor:	Bruce Mitchell
Processor Phone:	(850)413-9198
Processor Email Address:	Bruce.Mitchell@dep.state.fl.us

Or, Search for other Air Permit Documents on Florida's Air Permit Documents Search.

Please direct any questions regarding this permit application to the permit application processor. If you have any problems accessing these documents please let me know.

Thanks,

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-0771

Florida Department of
Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

September 19, 2008

Electronically Sent – Received Receipt Requested

Mr. David M. Lukcic
Manager of Environmental Programs
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

RE: Application for Authorization to Construct Two Simple Cycle Combustion Turbines and One Emergency Diesel Engine/Generator Set
Project No. 0570039-040-AC
Big Bend Power Station

Dear Mr. Lukcic:

On August 22, 2008, the Department of Environmental Protection (Department) received a request for authorization to construct two simple cycle combustion turbines and one emergency diesel engine/ generator set. Based on our review of the proposed project, we have determined that the following additional information is needed in order to continue processing this application package. Please provide all assumptions, calculations, and reference materials, that are used or reflected in any of your responses to the following issues:

1. Are you planning to convert these simple cycle combustion turbine (SCCT) systems into combined cycle CT systems? If so, when?

2. On the application page F.1. for a SCCT system, a total percent efficiency control value for the pollutant nitrogen oxides (NOx) is stated as 88%. What is the basis for the value and provide an explanation and/or the reference material to support this value?

3. On the application page F.1. for a SCCT system, a total percent efficiency control value for the pollutant carbon monoxide (CO) is stated as 90%. What is the basis for the value and provide an explanation and/or the reference material to support this value?

4. On the application page F.1. for a SCCT system, a total percent efficiency control value for the pollutant volatile organic compounds (VOC) is stated as 50%. What is the basis for the value and provide an explanation and/or the reference material to support this value?

5. For the proposed emergency diesel engine, where are you going to store the Ultra Low Sulfur Diesel (ULSD) fuel? Is there an existing ULSD fuel storage tank on-site? If so, please describe.

6. Explain how you plan to demonstrate compliance with the NOx emissions standard using the emissions monitoring provisions of Title 40, Code of Federal Regulations, Part 75 (40 CFR 75). Provide a detailed plan regarding this issue.

7. Please provide a detailed rule applicability determination for the provisions contained in 40 CFR 60, Subpart KKKK, for a SCCT.

8. Comments were received from the Hillsborough County Environmental Protection Commission. These comments are attached and must be addressed as part of this incompleteness letter.

The Department will resume processing this application after receipt of the requested information. If you have any questions regarding this matter, please call Bruce Mitchell at (850)413-9198.

Sincerely,

Syed Arif

Syed Arif, P.E.
New Source Review Section
Bureau of Air Regulation

SA/bm

Attachment

cc: Mr. David M. Lukcic, Tampa Electric Company (dmlukcic@tecoenergy.com)
Mr. Byron T. Burrows, Tampa Electric Company (btburrows@tecoenergy.com)
Mr. Thomas W. Davis, P.E., Environmental Consulting & Technology, Inc. (tdavis@ectinc.com)
Mr. Jerry Campbell, Hillsborough County Environmental Protection Commission (campbell@epchc.org)
Ms. Diana Lee, Hillsborough County Environmental Protection Commission, (Lee@epchc.org)
Mr. Roger Zhu, Hillsborough County Environmental Protection Commission, (Zhu@epchc.org)

MEMORANDUM

DATE: September 16, 2008

TO: Bruce Mitchell

FROM: Roger Zhu **THRU**: Diana M. Lee, P. E.
Sterlin Woodard, P.E.

SUBJECT: **TEC Big Bend Power Station (BBS) AC Application Review**
Construction of Two Simple-Cycle Combustion Turbines (SCCTs)
FDEP Project No. 0570039-040-AC

After reviewing the AC permit application received on August 26, 2008 for the construction of two SCCTs at TEC BBS site, the following comments are provided for your review:

1. This AC Permit Application is for construction/installation of a Pratt & Whitney Power System (PWPS) FT8-3 SWIFTPAC unit (CT Unit 4), which is comprised of two (2) SCCTs to one common generator, and also is for construction/installation of a 800 KW Caterpillar diesel engine, which provides electricity to CT Unit 4 in the event of power interruption from the grid. During this co-review, EPC staff acknowledges that the CT Unit 4 and the Caterpillar diesel engine are the identical units that will be installed at TEC Bayside site. However, the manufacturer specifications for these units were not included in the Bayside AC Permit Application dated 3/20/07 and 8/11/08 nor in this Big Bend AC Permit Application, except for information or data prepared and provided by the engineering consultant, ECT. Pursuant to Rules 62-4.070(1) and 62-210.200(244), F.A.C., and in order to verify the potential to emit, please provide design specifications on the SCCT. The specifications should include, but not limited to, design/operation parameters, the turbine heat input at peak load on either natural gas (NG) or ultra low sulfur diesel (ULSD)fuel usage.

2. Page 16 in the Application indicates that the maximum heat input rates are 342.7 MMBtu/hr for NG and 302.7 MMBtu/hr for ULSD. This AC project is subject to the NSPS, Subpart KKKK. Page 21 in the Application indicates that the NO_x emission standard for ULSD is 42 ppmvd @ 15% O_2, on which the emission estimates in Appendix B, Table B-7 and Table B-11, in the Application are based on. Table 1 of the NSPS, Subpart KKKK, shows the NO_x emission standard as 74 ppmvd @ 15% O_2 for a new turbine firing fuel other than NG with a range of heat input of 50 ~ 850 MMBtu/hr. Pursuant to Rule 62-4.070(1), F.A.C., please provide reasonable

assurance based on plans, test results and/or manufacturer's information or guarantees that the emission unit can meet the lower 42 ppmvd @ 15% O_2 NOx emission standard.

3. NSPS, Subpart KKKK, regulates and establishes emission standards for NO_x and SO_2. The NO_x and SO_2 PTE emissions estimates in the Application are calculated based on the emissions standards of the Subpart. Pursuant to Rule 62-4.070(1), F.A.C., please explain how the other air pollutants (CO, PM/PM_{10}, VOC, Pb and H_2SO_4 mist) hourly emission rate (lb/hr) are determined for a purpose of PTE estimates. According to the Application, the hourly emission rates, i.e., CO: 9.1 lb/hr; PM/PM_{10}: 7.5 lb/hr; VOC: 5.1 lb/hr, etc, appear to be from the vendor (PWPS) data. Pursuant to Rule 62-4.070(1), F.A.C., please provide justification for the PTE estimates and provide reasonable assurance based on plans, test results and/or manufacturer's information or guarantees that the emission unit can meet these emission rates and PTE limitations. Furthermore, have the emission factors in the AP-42, Table 3.1, been taken into consideration in comparison with the vendor data?

4. The 800 KW Caterpillar DSR4B Generator C27 TA Diesel Engine is subject to NSPS, Subpart IIII. The Section 4.1.2, Page 4-3, in the Application states that the diesel engine will have a displacement of less than 30 liters per cylinder. Pursuant to Rules 62-4.070(1) and 62-210.200(244), F.A.C., and in order to verify the potential to emit, please provide design specifications on the Caterpillar diesel engine. The specifications should include, but not limited to, design/operation parameters, the engine order/manufacture date, the actual displacement per cylinder, manufacturer certifications or engine testing data. In addition, pursuant to 40 CFR 60.4202©, it states that s*tationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines to the certification emission standards for new marine CI engines in* ***40 CFR 94.8****, as applicable, for all pollutants, for the same displacement and maximum engine power*. According to Appendix B, Table B-16, in the Application, the emission limits used for PTE estimates are calculated based on NO_x: 5.26 g/hp-hr; CO: 0.26 g/hp-hr; VOC: 0.03 g/hp-hr; PM/PM_{10}/PM2.$5_{2.5}$: 0.024 g/hp-hr and SO_2: 0.004 g/hp-hr. Pursuant to Rule 62-4.070(1), F.A.C., please provide reasonable assurance based on plans, test results and/or manufactures information or guarantees that the emission unit can meet these PTE limitations.

Livingston, Sylvia

From: Byron Burrows [btburrows@tecoenergy.com]

Sent: Friday, September 19, 2008 10:12 AM

To: Livingston, Sylvia

Subject: Re: RAI -0570039-040-AC (TECO Big Bend Power Station)

Hi Sylvia:
I can view the document.
Thanks,

Byron

>>> "Livingston, Sylvia" <Sylvia.Livingston@dep.state.fl.us> 09/19/08 9:57 AM >>>

Dear Sir/Madam:
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Thank you,

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-0771
sylvia.livingston@dep.state.fl.us

<<0570039-040-AC.pdf>>

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Michael W. Sole is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of service you received. Simply click on this link to the DEP Customer Survey. Thank you in advance for completing the survey.

Livingston, Sylvia

From: Tom Davis [tdavis@ectinc.com]

Sent: Friday, September 19, 2008 10:12 AM

To: Livingston, Sylvia

Subject: RE: RAI -0570039-040-AC (TECO Big Bend Power Station)

Sylvia,

I have received and can view the documents you provided.

Thanks.

From: Livingston, Sylvia [mailto:Sylvia.Livingston@dep.state.fl.us]
Sent: Friday, September 19, 2008 9:58 AM
To: btburrows@tecoenergy.com; dmlukcic@tecoenergy.com
Cc: tdavis@ectinc.com; campbell@epchc.org; Lee@epchc.org; Roger Zhu \('Roger Zhu \(E-mail\)'\); Arif, Syed; Walker, Elizabeth \(AIR\)
Subject: RAI -0570039-040-AC (TECO Big Bend Power Station)

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Thank you,

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Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-0771
sylvia.livingston@dep.state.fl.us

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Livingston, Sylvia

From: Andrew Nguyen [atnguyen@tecoenergy.com]
Sent: Friday, September 19, 2008 2:02 PM
To: Livingston, Sylvia
Subject: RE: Word Document Request

Thank you so much.

Have a great weekend.

Thuy

Andrew Thuy Nguyen
Senior Engineer, Air Programs
Environmental, Health & Safety
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601
Phone: 813-228-4654
Fax: 813-228-1308
Cell: 813-309-1341
ATNguyen@TECOenergy.com

>>> "Livingston, Sylvia" <Sylvia.Livingston@dep.state.fl.us> 09/19/2008 2:00:15 PM >>>
Andrew,

I've attached the requested documents to this email. Let me know if I can be of any further assistance.

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-0771
sylvia.livingston@dep.state.fl.us

From: Andrew Nguyen [mailto:atnguyen@tecoenergy.com]
Sent: Friday, September 19, 2008 1:46 PM
To: Livingston, Sylvia
Subject: Re: Word Document Request

Hi Sylvia,

The project No. is 0570039-040-AC
Big Bend Station - Simple Cycle Combustion Turbines and on Emergency Diesel Engine/Generator Set.

The letter was dated 9/19/08 addressed to David Lukcic of Tampa Electric.

Could you also send Hillsborough County EPC comment letter also? It was part of the RAI.

Thank you!!!

Andrew Thuy Nguyen
Senior Engineer, Air Programs
Environmental, Health & Safety

Tampa Electric Company
P.O. Box 111
Tampa, FL 33601
Phone: 813-228-4654
Fax: 813-228-1308
Cell: 813-309-1341
ATNguyen@TECOenergy.com

>>> "Livingston, Sylvia" <Sylvia.Livingston@dep.state.fl.us> 09/19/2008 1:39:36 PM >>>

Andrew,

Could you tell me again which RAI you needed the word document for?

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-0771
sylvia.livingston@dep.state.fl.us

TAMPA ELECTRIC

RECEIVED
SEP 24 2008
BUREAU OF AIR REGULATION

September 22, 2008

Mr. Syed Arif, P.E.
Florida Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

ViaEmail: Syed.Arif@dep.state.fl.us
Via FedEx
Airbill No. 7919 5615 3626

Re: Tampa Electric Company – Big Bend Station
Simple-Cycle Combustion Turbine Unit 4
Project No. 0570039-040-AC

Subject: Response to Request for Additional Information – September 19, 2008

Dear Mr. Arif:

Tampa Electric Company (TEC) submitted an air construction permit application to the Department on August 21, 2008 requesting authorization to install and operate two simple cycle combustion turbines at our Big Bend Station. In response to this permit application, the Department requested additional information in correspondence to TEC dated September 19, 2008.

This letter is intended to provide a response to each specific issue raised by the Department and the Hillsborough County Environmental Protection Commission (EPC). For your convenience, TEC has restated each issue followed by our response.

A. Florida Department of Environmental Protection Comments

FDEP-1

Are you planning to convert these simple cycle combustion turbine (SCCT) systems into combined cycle CT systems? If so, when?

TEC Response to FDEP-1

TEC does not plan to convert the simple-cycle combustion turbines (SCCTs) to combined-cycle units. The planned utilization of the SCCTs is described in Section 2.1 of the August 2008 air construction permit application.

FDEP-2

On the application page F. 1. for a SCCT system, a total percent efficiency control value for the pollutant nitrogen oxides (NO_x) is stated as 88%. What is the basis for the value and provide an explanation and/or the reference material to support this value?

TEC Response to FDEP-2

The 88 percent NO_x control efficiency associated with the SCCT water injection system was calculated based on a nominal uncontrolled (i.e., without water injection) NO_x exhaust concentration of 200 parts per million by volume (ppmvd) and a controlled (i.e., with water injection) NO_x exhaust concentration of 25 ppmvd as follows:

*NO_x Control Efficiency = [(200 ppmvd – 25 ppmvd) / 200 ppmvd] * 100 = 87.5 %*

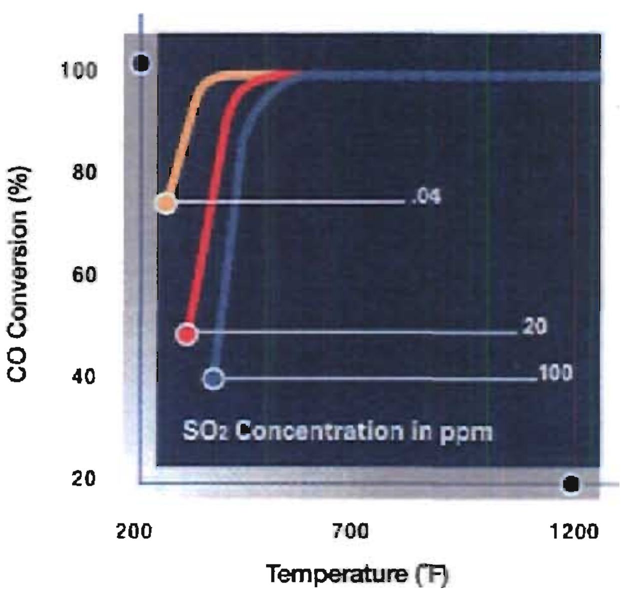
FDEP-3

On the application page F. I. for a SCCT system, a total percent efficiency control value for the pollutant carbon monoxide (CO) is stated as 90%. What is the basis for the value and provide an explanation and/or the reference material to support this value?

TEC Response to FDEP-3

The nominal 90 percent CO oxidation rate for the oxidation catalyst represents a typical CO conversion rate for this control technology. The actual CO oxidation rate of an oxidation catalyst system will depend on a number of variables including inlet CO concentration, residence time, and oxidation catalyst temperature.

Significant CO oxidation will occur at any catalyst temperature above roughly 500°F. As shown in Appendix B, Tables B-18 (for natural gas) and B-19 (for ULSD fuel oil) of the August 2008 air construction permit application, exhaust temperatures for the Pratt & Whitney Power Systems (PWPS) FT8-3® SWIFTPAC® SCCTs range from approximately 700 to 920 °F for both natural gas and ULSD fuel oil. The following graphic shows the relationship between catalyst temperature and CO conversion for a typical oxidation catalyst (data shown is for the BASF CAMET® catalyst; comparable performance would be expected for other catalyst vendors).



Removal efficiency will also vary with gas residence time that is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. For combustion turbine applications, oxidation catalyst systems are typically designed to achieve a control efficiency of 80 to 90 percent for CO.

The nominal 90 percent control efficiency shown on the FDEP permit application form is consistent with EPA information developed as part of the agency's rulemaking on the combustion turbine Maximum Achievable Control Technology (MACT) National Emission Standard for Hazardous Air Pollutants (NESHAPS). A December 30, 1999 memo from Mr. Sims Roy of EPA's Emissions Standards Division Combustion Group provides a discussion of oxidation catalyst systems. The December 30, 1999 EPA memorandum indicates that "The performance of these oxidation catalyst systems on combustion turbines results in 90-plus percent control of CO and about 85 to 90 percent control of formaldehyde. Similar emission reductions are also achieved on other hazardous air pollutants (HAP) pollutants." Similar language regarding the CO conversion rate of oxidation catalyst control technology is contained in Section 3.1 (Stationary Gas Turbines) of AP-42, Compilation of Air Pollutant Emission Factors; reference Section 3.1.4.3.

FDEP-4

On the application page F. I. for a SCCT system, a total percent efficiency control value for the pollutant volatile organic compounds (VOC) is stated as 50%. What is the basis for the value and provide an explanation and/or the reference material to support this value?

TEC Response to FDEP-4

The nominal 50 percent VOC oxidation rate shown on the FDEP permit application form for the oxidation catalyst represents a typical VOC oxidation rate for this control technology. Similar to CO, the VOC oxidation rate of an oxidation catalyst system will depend on a number of variables including inlet VOC concentration, residence time, catalyst temperature, and specific organic compound among others. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency using oxidation catalyst is 50 percent.

As noted above in the response to FDEP-1, the EPA reference cited indicates an expected conversion efficiency of formaldehyde and other HAPs in the range of 85 to 90 percent. Since formaldehyde and other organic HAPs are also VOCs, based on the EPA information the 50 percent VOC control efficiency assumed for the Big Bend Station Peaker Project is considered reasonable. This nominal VOC oxidation rate is also consistent with reviews conducted by regulatory agencies for similar projects. For example, in its review of the Sun Valley Energy Project (comprised of aeroderivative SCCTs similar to the PWPS SCCTs), the California Energy Commission concluded that "VOC emissions are expected to be further reduced as a result of the proposed CO oxidation catalyst. The amount of reduction is not estimated herein, but recent data indicate that VOC reductions on the order of 50-90 percent are routinely seen."

FDEP-5

For the proposed emergency diesel engine, where are you going to store the Ultra Low Sulfur Diesel (ULSD) fuel? Is there an existing ULSD fuel storage tank on-site? If so, please describe.

TEC Response to FDEP-5

There is an existing 4 million gallon (constructed prior to July 23, 1984) fuel oil storage tank located to the west of Big Bend Station SCCTs CT-2 and CT-3. This storage tank will be utilized to store ULSD fuel oil for the proposed PWPS FT8-3® SWIFTPAC® SCCTs. However, ULSD fuel oil storage for the emergency generator diesel engine will likely consist of either a small storage tank located near the engine or an integral tank located at the base of the engine.

FDEP-6

Explain how you plan to demonstrate compliance with the NOx emissions standard using the emissions monitoring provisions of title 40, Code of Federal Regulations, Part 75 (40 CFR 75). Provide a detailed plan regarding this issue.

TEC Response to FDEP-6

A detailed Part 75 monitoring plan is not available at this stage of the project. TEC will install NO_x *continuous emissions monitoring systems (CEMS) that comply with the requirements of 40 CFR Part 75. In accordance with 40 CFR §75.4(i)(2), monitoring system certification testing must be completed no later than 90 unit operating days or 180 calendar days (whichever occurs first) after the date the unit commences commercial operation. As required by 40 CFR §75.62, an initial monitoring plan will be submitted at least 21 days prior to the start of monitoring system certification testing. As noted on Page 1-2 of the August 2008 air construction permit application, commencement of commercial operation is planned for May 2009.*

FDEP-7

Please provide a detailed rule applicability determination for the provisions contained in 40 CFR 60, Subpart KKKK, for a SCCT.

TEC Response to FDEP-7

A highlighted version of 40 CFR 60, Subpart KKKK that shows the applicable sections of this New Source Performance Standard is attached – see Attachment 1 to this letter.

B. Hillsborough County Environmental Protection Commission Comments

EPC-1

This AC Permit Application is for construction/installation of a Pratt & Whitney Power System (PWPS) FT8-3 SWIFTPAC unit (CT Unit 4), which is comprised of two (2) SCCTs to one common generator, and also is for construction/installation of a 800 KW Caterpillar diesel engine, which provides electricity to CT Unit 4 in the event of power interruption from the grid. During this co-review, EPC staff acknowledges that the CT Unit 4 and the Caterpillar diesel engine are the identical units that will be installed at TEC Bayside site. However, the manufacturer specifications for these units were not included in the Bayside AC Permit Application dated 3/20/07 and 8/11/08 nor in this Big Bend AC Permit Application, except for information or data prepared and provided by the engineering consultant, ECT. Pursuant to Rules 62-4.070(1) and 62-210.200(244), F.A.C., and in order to verify the potential to emit, please provide design specifications on the SCCT. The specifications should include, but not limited to, design/operation parameters, the turbine heat input at peak load on either natural gas (NG) or ultra low sulfur diesel (ULSD) fuel usage.

TEC Response to EPC-1

PWPS technical data regarding the FT8-3® SWIFTPAC® SCCTs is provided in Attachment 2 to this letter.

EPC-2

Page 16 in the Application indicates that the maximum heat input rates are 342.7 MMBtu/hr for NG and 302.7 MMBtu/hr for ULSD. This AC project is subject to the NSPS, Subpart KKKK. Page 21 in the Application indicates that the NO_x emission standard for ULSD is 42 ppmvd @ 15% O_2, on which the emission estimates in Appendix B, Table B-7 and Table B-11, in the Application are based on. Table I of the NSPS, Subpart KKKK, shows the NO_x emission standard as 74 ppmvd @ 15% O_2 for a new turbine firing fuel other than NG with a range of heat input of 50 - 850 MMBtu/hr. Pursuant to Rule 62-4.070(1), F.A.C., please provide reasonable assurance based on plans, test results and/or manufacturer's information or guarantees that the emission unit can meet the lower 42 ppmvd @ 15% O_2 NO_x emission standard

TEC Response to EPC-2

PWPS has provided estimated emissions showing a NO_x exhaust concentration of 42 ppmvd @ 15% O_2 when firing ULSD fuel oil. This is the typical NO_x exhaust concentration provided by combustion turbine (CT) vendors for liquid fuel-fired CTs that are controlled by wet injection. Numerous liquid fuel-fired CTs that are controlled by wet injection have demonstrated the ability to achieve the 42 ppmvd @ 15% O_2 NO_x concentration; e.g., the Seminole Electric Cooperative Midulla Generating Station PWPS FT8-3® SWIFTPAC® SCCTs. PWPS technical data regarding the FT8-3® SWIFTPAC® SCCTs is provided in Attachment 2 to this letter.

EPC-3

NSPS, Subpart KKKK, regulates and establishes emission standards for NO_x and SO_2. The NO_x and SO_2 PTE emissions estimates in the Application are calculated based on the emissions standards of the Subpart. Pursuant to Rule 62-4.070(1), F.A.C., please explain how the other air pollutants (CO, PM/PM_{10}, VOC, Pb and H_2S0_4 mist) hourly emission rate (lb/hr) are determined for a purpose of PTE estimates. According to the Application, the hourly emission rates, i.e., CO: 9.1 lb/hr; PM/PM_{10}: 7.5 lb/hr; VOC: 5.1 lb/hr, etc, appear to be from the vendor (PWPS) data. Pursuant to Rule 62-4.070(1), F.A.C., please provide justification for the PTE estimates and provide reasonable assurance based on plans, test results and/or manufacturer's information or guarantees that the emission unit can meet these emission rates and PTE limitations. Furthermore, have the emission factors in the AP-42, Table 3.1, been taken into consideration in comparison with the vendor data?

TEC Response to EPC-3

The hourly and annual potential-to-emit (PTE) emission rates for the PWPS FT8-3® SWIFTPAC® SCCTs were calculated based on PWPS estimated emissions data and the maximum annual operating hours proposed for the Big Bend Station Peaker Project. Emission rate calculations were provided in Appendix B, Tables B-1 through B-20 of the August 2008 air construction permit application. PWPS technical data, including estimated emissions, for the FT8-3® SWIFTPAC® SCCTs is provided in Attachment 2 to this letter. A detailed explanation of each Appendix B emission rate calculation is provided in Attachment 3 to this letter. In reviewing the emission rate calculations provided in Appendix B, it was noticed that several tables inadvertently used a 5.0 percent heat input margin instead of the correct 7.0 percent margin. Revised Appendix B tables are provided in Attachment 5 to this letter.

EPC-4

The 800KW Caterpillar DSR4B Generator C27 TA Diesel Engine is subject to NSPS, Subpart IIII. The Section 4.1.2, Page 4-3, in the Application states that the diesel engine will have a displacement of less than 30 liters per cylinder. Pursuant to Rules 62-4.070(1) and 62-210.200(244), F.A.C., and in order to verify the potential to emit, please provide design specifications on the Caterpillar diesel engine. The specifications should include, but not limited to, design/operation parameters, the engine order/manufacture date, the actual displacement per cylinder, manufacturer certifications or engine testing data. In addition, pursuant to 40 CFR 60.4202, it states that *stationary CI internal combustion engine manufacturers must certify their 2007 mode/year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines to the certification emission standards for new marine CI engines in **40 CFR 94.8**, as applicable, for all pollutants, for the same displacement and maximum engine power.* According to Appendix B, Table B-16, in the Application, the emission limits used for PTE estimates are calculated based on NO_x: 5.26 g/hp-hr; CO: 0.26 g/hp-hr; VOC: 0.03 g/hp-hr; $PM/PM_{10}/PM_{2.5}$: 0.024 g/hp-hr and SO_2: 0.004 g/hp-hr. Pursuant to Rule 62-4.070(1), F.A.C., please provide reasonable assurance based on plans, test results and/or manufactures information or guarantees that the emission unit can meet these PTE limitations.

TEC Response to EPC-3

Technical information, including emission rates for the Caterpillar C27 TA emergency diesel engine is provided in Attachment 4 to this letter. The emergency generator diesel engine for the Big Bend Station Peaker Project is expected to be a model year 2007 or later unit with a cylinder displacement less than 10 liters per cylinder and a maximum engine power greater than 50 horsepower (HP). Accordingly, the diesel engine would be subject to the requirements of New Source Performance Standard (NSPS) Subpart IIII 40 CFR §60.4202(a)(2) [for engine manufacturers), and §60.4205(b) [for owners and operators]. Both of these provisions require engine certification to the emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

Note that, beginning with engines manufactured in model year 2007, engine manufacturers are required to produce engines that are certified to comply with NSPS Subpart IIII. Regardless of the specific emission standards that may apply to a particular model year engine, TEC will only purchase an engine for the Big Bend Station Peaker Project that is certified to comply with NSPS Subpart IIII.

TEC understands that with the submission of this additional information and the revised air construction permit application, the Department will continue processing our request for an air construction permit for Big Bend Station simple cycle Unit 4. If you have any further questions regarding this matter, please contact me at (813) 228-1095.

Sincerely,

David M. Lukcic
Manager Environmental Projects
Environmental Health and Safety

Attachments

cc: Mr. Bruce Mitchell, FDEP
Ms. Diana Lee, EPCHC (enc)

bc: B.T. Burrows
A.T. Nguyen
J.M. Ward
R.L. Kelleher
Tom Davis, ECT
C.2.1

EHS/TWD/ATN003

ATTACHMENT 1

RESPONSE TO FDEP-7

APPLICABLE PROVISIONS OF 40 CFR 60, SUBPART KKKK
NEW SOURCE PERFORMANCE STANDARDS
FOR STATIONARY GAS TURBINES

Applicable requirements for natural gas
Applicable requirements for ULSD fuel oil
Applicable requirements for both natural gas and ULSD fuel oil

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Source: 71 FR 38497, July 6, 2006, unless otherwise noted.

Introduction

§ 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

§ 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NO_X) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_X emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

(a) You must meet the emission limits for NO_X specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

§ 60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1) or (a)(2) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Monitoring

§ 60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?

(a) If you are using water or steam injection to control NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2concentration exceeds 19.0 percent O_2(or the hourly average CO_2concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2or 1.0 percent CO_2(as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_X)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$= hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$= hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), e.g. , calculated using Equation D–15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad \text{(Eq. 2)}$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$= electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$= electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad \text{(Eq. 3)}$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 10_6= conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_X)_m}{BL * AL} \qquad \text{(Eq. 4)}$$

Where:

E = NO_X emission rate in lb/MWh,

$(NO_X)_m$= NO_X emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_X CEMS is chosen:

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§ 60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(iii) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NO_X emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.* , flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§ 60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§ 60.4380 How are excess emissions and monitor downtime defined for NOX?

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_X control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3

of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NO_X limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_X limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad \text{(Eq. 5)}$$

Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7}= conversion constant, in lb/dscf-ppm

$(NO_X)_c$= average NO_X concentration for the run, in ppm

Q_{std}= stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(ii) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_X emission rate in lb/MWh.

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2(or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2(or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2(or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NO_X emission limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

(2) Measure the SO_2concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad \text{(Eq. 6)}$$

Where:

E = SO_2emission rate, in lb/MWh

1.664×10^{-7}= conversion constant, in lb/dscf-ppm

$(SO_2)_c$= average SO_2concentration for the run, in ppm

Q_{std}= stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(3) Measure the $SO_2$and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2emission rate in lb/MWh.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

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

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

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

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines 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 combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_X emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

Table 1—to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	**Combustion turbine heat input at peak load (HHV)**	**NO_X emission standard**
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).

New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

ATTACHMENT 2

RESPONSE TO EPC-1

TECHNICAL DATA FOR PRATT & WHITNEY POWER SYSTEM
FT8-3® SWIFTPAC® SIMPLE CYCLE COMBUSTION TURBINES

SWIFTPAC® **Power Plant**

SWIFTPAC Power Plants Provide Quick, Reliable Power. Installation Takes Less Than 30 Days.

SWIFTPAC transportable power plants offer 30 or 60 MW of moveable power. Utilizing the proven Pratt & Whitney Power Systems FT8 technology, SWIFTPAC transportable power plants are designed to provide quick, reliable power. The package design includes an enclosed driver assembly incorporating the gas generator, power turbine, exhaust collector box, inlet plenum and lube system. This factory-assembled module allows the SWIFTPAC to be generating power less than 30 days after arriving on site.

Pratt & Whitney. **The Eagle is everywhere.**™

Benefits

- Best-in-class part load efficiency
- Reduced site setup time
- Lower site cost
- Less expensive shipping
- Reduced field flushing
- Minimal field wiring terminations
- Prefabricated piping needs no field welding
- Less site labor
- Standard and repeatable manufacturing process
- Standard and repeatable installation process
- Preassembled and tested
- Reduced field inventory
- Ease of engine checkout and maintenance
- Operating flexibility

FT8® SWIFTPAC® POWER PLANT

SWIFTPAC Power Plants Provide Quick, Reliable Power. Installation Takes Less Than 30 Days.

Enhancements

- Factory-assembled modules
- Integrated lube oil system
- Factory-tested quick disconnect cables
- Prefabricated field piping
- Factory-flushed lube oil systems
- Combined GT and exhaust enclosure
- Factory checkout
- Simple roadbed foundation
- Compact layout

Pratt & Whitney
A United Technologies Company

Pratt & Whitney Power Systems

1-866-POWER-ALL (1-866-769-3725)
Outside USA: 1-860-565-0140
Email: info@pw.utc.com

Visit Pratt & Whitney at www.pw.utc.com

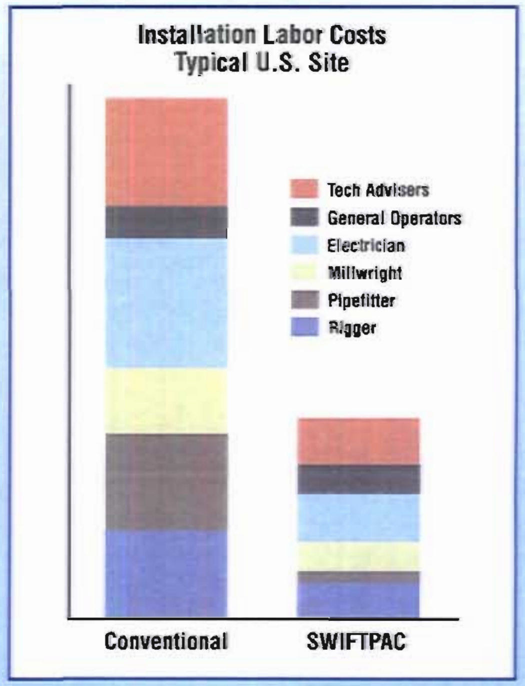
Product Facts

Simple Cycle Performance

Natural Gas

	SWIFTPAC 30	SWIFTPAC 60
Output (kW)	30446	61196
Heat Rate		
(BTU/kW-hr)	9312	9266
Efficiency (%)	37	37
Exhaust Flow (lb/sec)	201	402
Exhaust Temp (°F)	895	895
U.S. Transport Time	6 days	6 days
Foundation	2-3' concrete	3' concrete
Installation	3 weeks	3 weeks
NOx	25	25
Fuel	Dual	Dual
Frequency	50/60 HZ	50/60 HZ

Also available with DLN and/or inlet fogging.



rev 11.7.07

FT8-3 Swift Pac (with CO Converter)
Estimated Performance and Emissions, Part-Load Data
Tampa-Electric

Configuration: Standard NE US Gas Fuel, WI to 25 ppmvd NOx @ 15% O2,
Sea Level Alt., 55% Ambient RH, 72-290 Generator at 60 Hz, 13.8 kV, 0.85 pf Simple-Cycle

Performance Data										
Fuel Type		Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Percent of Swift Pac Unit Rating	%	100	75	50	100	75	50	100	75	50
Ambient Temperature	Deg F	20	20	20	59	59	59	90	90	90
Evaporative Cooler In-Service	Yes / No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes
Chiller in Service	Yes / No	No	No	No	No	No	No	No	No	No
Compressor Inlet Temperature	Deg F	20	20	20	52	52	52	79	79	79
Ambient Pressure	Psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Relative Humidity	%	55	55	55	55	55	55	55	55	55
Inlet Loss	Inch H20	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Exhaust Loss	Inch H20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Fuel Supply Temperature	Deg F	59	59	59	59	59	59	59	59	59
Fuel LHV	Btu/lb	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671
Fuel HHV	Btu/lb	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932
Ratio of HHV to LHV		1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109
Gross Power Output	MWe	62.501	46.876	31.251	62.155	46.617	31.078	57.586	43.19	28.793
Gross Heat Rate, HHV	Btu/kWhr	10,125	10,442	11,517	10,306	10,652	11,738	10,495	11,013	12,181
Power Island and Evap Aux Loads	kW	252	252	252	260	260	260	260	260	260
Net Power Output	MWe	62.249	46.624	30.999	61.895	46.357	30.818	57.326	42.930	28.533
Net Heat Rate, HHV	Btu/kWhr	10,166	10,499	11,611	10,349	10,712	11,837	10,543	11,080	12,292
Fuel Flow, per GT	lbs/hr	13,797	10,673	7,847	13,967	10,827	7,954	13,177	10,371	7,647
Burner Water Injection Flow, per GT	gal/min	29.4	20.4	13.3	31.3	21.9	14.5	29.7	21.5	14.4
EVAP Water Flow Rate, per GT	gal/min	0.0	0.0	0.0	2.3	2.1	1.8	3.4	3.1	2.6
Gaseous Fuel Flow @ 15C, per GT	SCF/hr	306,139	236,811	174,125	309,905	240,229	176,484	292,386	230,119	169,676
Emissions at GT Exit*										
NOx	ppmvd	25	25	25	25	25	25	25	25	25
NOx, as NO2, per GT	lbs/hr	31.6	24.4	18.2	32.0	24.8	18.2	30.2	23.7	17.5
VOC as C1	ppmvd	6.0	15.6	40.4	6.0	11.0	17.2	6.0	7.6	16.0
VOC as C1, per GT	lbs/hr	2.6	5.3	10.1	2.7	3.8	4.3	2.5	2.5	3.9
SO2	ppmvd	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
SO2, per GT	lbs/hr	0.48	0.37	0.27	0.49	0.38	0.28	0.46	0.36	0.27
TSP/PM10, Filterable and Cond, per GT	lbs/hr	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Exhaust Gas Flow, per GT **	lbs/sec	212	190	161	204	182	153	192	169	143
Exhaust Gas Temperature **	Deg F	828	748	701	893	817	767	917	864	814
Exhaust Gas Molecular Weight, Wet		28.23	28.36	28.46	28.08	28.21	28.31	27.89	28.00	28.10
Exhaust Gas Vol Flow Rate, per GT **	ACFS	7,058	5,910	4,783	7,166	6,000	4,847	6,917	5,843	4,734
Stack Exhaust Velocity, per GT **	ft/s	99.6	83.4	67.5	101.1	84.6	68.4	97.6	82.4	66.8
H2O	% Vol wet	9.25	7.76	6.57	10.77	9.29	8.05	12.45	11.24	10.00
O2	% Vol wet	13.5	14.6	15.4	12.9	14.0	14.9	12.6	13.5	14.4
CO2	% Vol wet	3.14	2.72	2.38	3.29	2.88	2.52	3.27	2.93	2.57
A	% Vol wet	0.871	0.881	0.889	0.858	0.868	0.877	0.842	0.851	0.859
N2	% Vol wet	73.2	74.1	74.7	72.1	73.0	73.7	70.8	71.5	72.2
Treated Exhaust Characteristics (Post CO Converter)*										
CO		8.0	14.1	20.9	6.0	11.6	14.8	6.0	9.3	14.3
CO, per GT		6.2	8.4	9.1	4.7	7.0	6.6	4.4	5.4	6.1

Notes:
* All ppmvd corrected to 15% O2
** Secondary Cooling Air Separately Exhausted

Guaranteed values are indicated by (G), or $\boxed{\text{value}}$
All other data are estimates.

Source: PWPS, 2008.

FT8-3 Swift Pac (with CO Converter)
Estimated Performance and Emissions, Part-Load Data
Tampa-Electric

Configuration: Specified Liquid Fuel (ULSD), WI to 42 ppmvd NOx @ 15% O2,
Sea Level Alt., 55% Ambient RH, 72-290 Generator at 60 Hz, 13.8 kV, 0.85 pf Simple-Cycle

Performance Data										
Fuel Type		Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
Percent of Swift Pac Unit Rating	%	100	75	50	100	75	50	100	75	50
Ambient Temperature	Deg F	20	20	20	59	59	59	90	90	90
Evaporative Cooler In-Service	Yes / No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes
Chiller in Service	Yes / No	No	No	No	No	No	No	No	No	No
Compressor Inlet Temperature	Deg F	20	20	20	52	52	52	79	79	79
Ambient Pressure	Psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Relative Humidity	%	55	55	55	55	55	55	55	55	55
Inlet Loss	Inch H20	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Exhaust Loss	Inch H20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Fuel Supply Temperature	Deg F	127	127	127	127	127	127	127	127	127
Fuel LHV	Btu/lb	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360
Fuel HHV	Btu/lb	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553
Ratio of HHV to LHV		1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065
Gross Power Output	MWe	56.065	42.049	28.033	56.167	42.125	28.084	56.02	42.015	28.01
Gross Heat Rate, HHV	Btu/kWhr	9,877	10,396	11,533	10,075	10,592	11,739	10,263	10,797	11,950
Power Island and Evap Aux Loads	kW	277	277	277	285	285	285	285	285	285
Net Power Output	MWe	55.788	41.772	27.756	55.882	41.84	27.799	55.735	41.73	27.725
Net Heat Rate, HHV	Btu/kWhr	9,926	10,465	11,648	10,126	10,665	11,860	10,315	10,870	12,073
Fuel Flow, per GT	lbs/hr	14,159	11,178	8,267	14,470	11,409	8,430	14,701	11,599	8,559
Burner Water Injection Flow, per GT	gal/min	29.6	21.1	13.7	32.2	23.1	15.1	34.3	24.8	16.3
EVAP Water Flow Rate, per GT	gal/min	0.0	0.0	0.0	2.3	2.0	1.7	3.4	3.0	2.6
Gaseous Fuel Flow @ 15C, per GT	SCF/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emissions at GT Exit*										
NOx	ppmvd	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**
NOx, as NO2, per GT	lbs/hr	49.4	38.9	28.7	50.5	39.8	29.3	51.3	40.4	29.8
VOC as C1	ppmvd	**5.0**	**8.7**	**25.4**	**5.0**	**5.0**	**13.1**	**5.0**	**5.0**	**7.8**
VOC as C1, per GT	lbs/hr	2.0	2.8	6.0	2.1	1.6	3.2	2.1	1.7	1.9
SO2	ppmvd	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
SO2, per GT	lbs/hr	0.47	0.37	0.27	0.48	0.38	0.28	0.49	0.38	0.28
TSP/PM10, Filterable and Cond, per GT	lbs/hr	**7.5**	**7.5**	**7.5**	**7.5**	**7.5**	**7.5**	**7.5**	**7.5**	**7.5**
Exhaust Gas Flow, per GT **	lbs/sec	205	182	154	197	174	147	190	168	142
Exhaust Gas Temperature **	Deg F	793	744	699	864	814	767	921	872	823
Exhaust Gas Molecular Weight, Wet		28.64	28.70	28.76	28.49	28.56	28.63	28.27	28.34	28.41
Exhaust Gas Vol Flow Rate, per GT **	ACFS	6,558	5,567	4,534	6,688	5,669	4,610	6,788	5,750	4,669
Stack Exhaust Velocity, per GT **	ft/s	92.5	78.5	64.0	94.4	80.0	65.0	95.8	81.1	65.9
H2O	% Vol wet	6.85	5.86	4.88	8.41	7.37	6.31	10.63	9.57	8.45
O2	% Vol wet	14.2	14.9	15.7	13.5	14.3	15.2	12.8	13.6	14.5
CO2	% Vol wet	4.00	3.58	3.13	4.23	3.79	3.32	4.42	3.97	3.48
A	% Vol wet	0.882	0.889	0.897	0.868	0.876	0.884	0.849	0.857	0.865
N2	% Vol wet	74.1	74.7	75.3	73.0	73.6	74.3	71.3	72.0	72.7
Treated Exhaust Characteristics (Post CO Converter)*										
CO		**2.1**	**3.2**	**5.1**	**2.0**	**2.3**	**3.8**	**2.0**	**2.0**	**3.8**
CO, per GT		1.5	1.8	2.1	1.5	1.4	1.6	1.5	1.2	0.6

Notes:
* All ppmvd corrected to 15% O2
** Secondary Cooling Air Separately Exhausted

Guaranteed values are indicated by (G), or **value** (boxed)
All other data are estimates.

Source: PWPS, 2008.

ATTACHMENT 3

RESPONSE TO EPC-3

EXPLANATION OF APPENDIX B
EMISSION RATE CALCULATIONS

TEC BIG BEND STATION
SIMPLE CYCLE COMBUSTION TURBINES UNIT 4
EXPLANATION OF APPENDIX B EMISSION RATE CALCULATIONS

Emissions data for the Pratt & Whitney Power Systems (PWPS) FT8-3 SWIFTPAC simple cycle combustion turbines (SCCTs) are provided in Appendix B of the permit application, Tables B-1 through B-20. The following sections provide the basis for each emission rate calculation.

Note that the calculation results provided in Tables B-1 through B-20 used the full electronic spreadsheet precision; i.e., were not rounded. For this reason, a check of the calculations using the data shown in Tables B-1 through B-20 may, in some cases, produce slightly different results because the tables do not display all of the 15 digits used by the electronic spreadsheet.

Table B-1: SCCT Annual Emission Rate Summary

The criteria pollutant emissions on this table are taken directly from Tables B-10 and B-11 for the SCCTs, and from Table B-16 for the emergency engine. HAPs are shown for the SCCTs only, and were taken from Table B-9. The H_2SO_4 mist emission rate is also taken from Tables B-10 and B-11 for the SCCTs. CO_2 emission rates, based on emission factors, heat input rates, and operating hours, were calculated as shown below. Annual emission rates for the SCCTs represent the maximum values from Table B-10 (Annual Profile #1 - 3,500 hrs/yr natural gas) and Table B-11 (Annual Profile #2 - 3,000 hrs/yr natural gas and 500 hrs/yr ULSD fuel oil).

CO_2 Calculation for the SCCTs:

AP-42 CO_2 Emission Factor (Natural Gas) = 110 lb/MMBtu (from AP-42 Table 3.1-2a)

AP-42 CO_2 Emission Factor (ULSD Fuel Oil) = 157 lb/MMBtu (from AP-42 Table 3.1-2a)

Heat Input per SCCT (Natural Gas) = 342.7 MMBtu/hr (from Table B-13, Case 4)

Heat Input per SCCT (ULSD Fuel Oil) = 302.7 MMBtu/hr (from Table B-15, Case 4)

Annual Operating Hours = 3,000 hrs/yr (natural gas and 500 hrs/yr ULSD fuel oil
(From Table B-2, Annual Profile #2)

CO_2 = [(110 lb/MMBtu x 342.7 MMBtu/hr x 3,000 hr/yr) +
(157 lb/MMBtu x 302.7 MMBtu/hr x 500 hr/yr)] x (1 ton /2,000 lb)
x 2 SCCTs = 136,865 ton/yr

CO_2 Calculation for the Emergency Engine:

AP-42 CO_2 Emission Factor = 165 lb/MMBtu (from AP-42 Table 3.4-1)

Heat Input per Engine = 7.89 MMBtu/hr (from Table B-17)

Annual Operating Hours = 100 hours per year (from Table B-17)

CO_2 = 165 lb/MMBtu x 7.89 MMBtu/hr x 100 hr/yr x ton/2,000 lb x 1 engine = 65 ton/yr

Table B-2: SCCT Operating Scenarios

Operating scenarios identified in Table B-2 represent the range of loads (50 to 100 percent), approximate ambient temperatures (20 to 90°F), fuel types (natural gas and ULSD fuel oil), and use of evaporative cooling under which Unit 4 will operate.

TEC BIG BEND STATION
SIMPLE CYCLE COMBUSTION TURBINES UNIT 4
EXPLANATION OF APPENDIX B EMISSION RATE CALCULATIONS

Table B-3: Hourly PM/PM$_{10}$, SO$_2$, H$_2$SO$_4$ Mist, and Pb Emission Rates (per SCCT) - Natural Gas

A. PM/PM$_{10}$

For each ambient temperature and SCCT operating load, PM/PM$_{10}$ emissions in lb/hr were based on PWPS data for PM/PM$_{10}$ as measured by EPA Reference Methods 201 or 201A, and 202. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 2; 20°F ambient temperature, 75% load

PWPS PM/PM$_{10}$ = 2.5 lb/hr

PM/PM$_{10}$ = 2.5 lb/hr x 0.126 = 0.32 g/s

B. SO$_2$

For each ambient temperature and SCCT operating load, SO_2 emissions in lb/hr were based on PWPS fuel flow data, natural gas sulfur content of 2.0 gr S/100 ft^3, natural gas density of 0.0451 lb/ft^3, and conversion factor of 7,000 grains per pound. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 4; 59°F ambient temperature, 100% load

Fuel Flow = 13,967 lb/hr NG

Margin = 7%

Adjusted Fuel Flow = Fuel Flow x Margin = 13,967 lb/hr x 1.07 =14,945 lb/hr

SO_2 = (14,945 lb/hr NG) x (2.0 gr S / 100 ft^3) x (ft^3 / 0.0451 lb NG)

x (1 lb S / 7,000 gr S) x (2 lb SO_2 / 1 lb S)

SO_2 = 1.89 lb/hr

SO_2 = 1.89 lb/hr x 0.126 = 0.24 g/s

C. H$_2$SO$_4$

For each ambient temperature and SCCT operating load, H_2SO_4 emissions in lb/hr were based on an assumed 7.5% conversion rate by volume of SO_2 to H_2SO_4. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 7; 90°F ambient temperature, 100% load

SO_2 = 1.79 lb/hr

H_2SO_4 = (1.79 lb/hr SO_2) x (7.5 / 100) x (98 lb-mole H_2SO_4 / 64 lb-mole SO_2)

H_2SO_4 = 0.21 lb/hr

H_2SO_4 = 0.21 lb/hr x 0.126 = 0.026 g/s

TEC BIG BEND STATION
SIMPLE CYCLE COMBUSTION TURBINES UNIT 4
EXPLANATION OF APPENDIX B EMISSION RATE CALCULATIONS

D. Lead

For each ambient temperature and SCCT operating load, estimates of lead emission rates were developed using an emission factor from EPA AP-42 (Section 1.4 Natural Gas Combustion, Table 1.4-2), and PWPS heat input rates.

Example: Case 1; 20°F ambient temperature, 100% load

PWPS Fuel Flow = 14,763 lb/hr (with margin)

Heat Input = 14,763 lb/hr x 22,933 Btu/lb [HHV] = 338.6 x 10^6 Btu/hr [HHV]

Lead Emission Factor = 4.9 x 10^{-7} lb / 10^6 Btu

Lead = (338.6 x 10^6 Btu/hr) x (4.9 x 10^{-7} lb / 10^6 Btu)

Lead = 0.00017 lb/hr (Negligible)

Table B- 4: NO_x, CO, and CO Emission Rates (per SCCT) - Natural Gas

A. NO_x

For each ambient temperature and SCCT operating load, NO_x emissions in ppmvd at 15% O_2 and lb/hr were based on PWPS data. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 3; 20°F ambient temperature, 50% load

PWPS NO_x = 25 ppmvd @ 15% O_2 PWPS NO_x = 18.2 lb/hr

NO_x = 18.2 lb/hr

NO_x = 18.2 lb/hr x 0.126 = 2.29 g/s

B. CO

For each ambient temperature and SCCT operating load, CO emissions in ppmvd at 15% O_2 and lb/hr were based on PWPS data. The efficiency of the oxidation catalyst was used to determine the final emissions in the exhaust. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 7; 90°F ambient temperature, 100% load

PWPS CO = 60 ppmvd @ 15% O_2 PWPS CO = 44.1 lb/hr

Oxidation Catalyst Efficiency = 90%

CO = 44.1 lb/hr x (100-90)/100 = 4.4 lb/hr

CO = 4.4 lb/hr x 0.126 = 0.55 g/s

C. VOC

For each ambient temperature and SCCT operating load, VOC emissions in ppmvd at 15% O_2 and lb/hr were based on PWPS data. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 5; 59°F ambient temperature, 75% load

PWPS VOC = 11.1 ppmvd @ 15% O_2 PWPS VOC = 3.8 lb/hr

Oxidation Catalyst Efficiency = 50%

VOC = 3.8 lb/hr x (100-50)/100 = 1.9 lb/hr

VOC = 1.9 lb/hr x 0.126 = 0.24 g/s

Table B-5: Hazardous Air Pollutant Hourly Emission Rates (Per SCCT) - Natural Gas

Estimates of hazardous air pollutant emission rates were developed using emission factors from the references shown at the bottom of Table B-5 and PWPS heat input data for each operating case. As indicated in the second footnote of the table, the emission factors for the organic compounds have been adjusted to account for the control efficiency of the oxidation catalyst. The maximum hourly heat input rate occurs at 59°F ambient temperature, 100% load i.e., Case 4. For annual emission estimates, maximum values from Table B-9 were used.

Example: Maximum Hourly Naphthalene; Case 1; 20°F ambient temperature, 100% load

PWPS SCCT Heat Input = 338.6 x 10^6 Btu/hr [HHV] (with margin)

Naphthalene AP-42 Emission Factor = 1.30 x 10^{-6} lb / 10^6 Btu

Since naphthalene is an organic, the emission factor is adjusted to account for 50% control efficiency.

Adjusted Emission Factor = 1.30 x 10^{-6} lb / 10^6 Btu x 0.5 = 6.50 x 10^{-7} lb / 10^6 Btu

Naphthalene = (338.6 x 10^6 Btu/hr) x (6.50 x 10^{-7} lb / 10^6 Btu)

Naphthalene = 2.20 x 10^{-4} lb/hr

Table B-6: Hourly PM/PM_{10}, SO_2, H_2SO_4 Mist, and Pb Emission Rates (per SCCT) –ULSD Fuel Oil

A. PM/PM_{10}

For each ambient temperature and SCCT operating load, PM/PM_{10} emissions in lb/hr were based on PWPS data for PM/PM_{10} as measured by EPA Reference Methods 201 or 201A, and 202. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 2; 20°F ambient temperature, 75% load

PWPS PM/PM_{10} = 7.5 lb/hr

PM/PM_{10} = 7.5 lb/hr x 0.126 = 0.95 g/s

B. SO_2

For each ambient temperature and SCCT operating load, SO_2 emissions in lb/hr were based on PWPS ULSD fuel oil flow data and sulfur content of 0.0015 weight percent. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 4; 59°F ambient temperature, 100% load

Fuel Flow = 14,470 lb/hr ULSD fuel oil

Margin = 7%

Adjusted Fuel Flow = Fuel Flow x Margin = 14,470 lb/hr x 1.07 =15,483 lb/hr

SO_2 = (15,483 lb/hr ULSD) x (0.0015 lb S / 100 lb ULSD) x (2 lb SO_2 / 1 lb S)

SO_2 = 0.46 lb/hr

SO_2 = 0.46 lb/hr x 0.126 = 0.06 g/s

C. H_2SO_4

For each ambient temperature and SCCT operating load, H_2SO_4 emissions in lb/hr were based on an assumed 7.5% conversion rate by volume of SO_2 to H_2SO_4. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 7; 90°F ambient temperature, 100% load

SO_2 = 0.47 lb/hr

H_2SO_4 = (0.47 lb/hr SO_2) x (7.5 / 100) x (98 lb-mole H_2SO_4 / 64 lb-mole SO_2)

H_2SO_4 = 0.054 lb/hr

H_2SO_4 = 0.054 lb/hr x 0.126 = 0.0068 g/s

D. Lead

For each ambient temperature and SCCT operating load, estimates of lead emission rates were developed using the ULSD Pb emission factor from Table B-8 and PWPS heat input rates.

Example: Case 1; 20°F ambient temperature, 100% load

PWPS Fuel Flow = 15,150 lb/hr (with margin)

Heat Input = 15,150 lb/hr x 19,553 Btu/lb [HHV] = 296.2 x 10^6 Btu/hr [HHV].

Lead Emission Factor = 7.67 x 10^{-7} lb / 10^6 Btu

Lead = (296.2 x 10^6 Btu/hr) x (7.67 x 10^{-7} lb / 10^6 Btu)

Lead = 0.00023 lb/hr (Negligible)

Table B- 7: NO_x, CO, and CO Emission Rates (per SCCT) – ULSD Fuel Oil

A. NO_x

For each ambient temperature and SCCT operating load, NO_x emissions in ppmvd at 15% O_2 and lb/hr were based on PWPS data. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 3; 20°F ambient temperature, 50% load

PWPS NO_x = 42 ppmvd @ 15% O_2 PWPS NO_x = 28.7 lb/hr

NO_x = 28.7 lb/hr

NO_x = 28.7 lb/hr x 0.126 = 3.62 g/s

B. CO

For each ambient temperature and SCCT operating load, CO emissions in ppmvd at 15% O_2 and lb/hr were based on PWPS data. The efficiency of the oxidation catalyst was used to determine the final emissions in the exhaust. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 7; 90°F ambient temperature, 100% load

PWPS CO = 20 ppmvd @ 15% O_2 PWPS CO = 15.0 lb/hr

Oxidation Catalyst Efficiency = 90%

CO = 15.0 lb/hr x (100-90)/100 = 1.5 lb/hr

CO = 1.5 lb/hr x 0.126 = 0.19 g/s

C. VOC

For each ambient temperature and SCCT operating load, VOC emissions in ppmvd at 15% O_2 and lb/hr were based on PWPS data. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 5; 59°F ambient temperature, 75% load

PWPS VOC = 5.0 ppmvd @ 15% O_2 PWPS VOC = 1.6 lb/hr

Oxidation Catalyst Efficiency = 50%

VOC = 1.6 lb/hr x (100-50)/100 = 0.8 lb/hr

VOC = 0.8 lb/hr x 0.126 = 0.10 g/s

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Table B-8: Hazardous Air Pollutant Hourly Emission Rates (Per SCCT) – ULSD Fuel Oil

Estimates of hazardous air pollutant emission rates were developed using emission factors from the references shown at the bottom of Table B-8 and PWPS heat input data for all operating cases. As indicated in the third footnote of the table, the emission factors for the organic compounds have been adjusted to account for the control efficiency of the oxidation catalyst. The maximum hourly heat input rate occurs at 90°F ambient temperature, 100% load i.e., Case 7. For annual emission estimates, maximum values from Table B-9 were used.

Example: Maximum Hourly Naphthalene; Case 7; 90°F ambient temperature, 100% load

PWPS SCCT Heat Input = 307.6 x 10^6 Btu/hr [HHV] (with margin)

Naphthalene AP-42 Emission Factor = 3.50 x 10^{-5} lb / 10^6 Btu

Since naphthalene is an organic, the emission factor is adjusted to account for 50% control efficiency.

Adjusted Emission Factor = 3.50 x 10^{-5} lb / 10^6 Btu x 0.5 = 1.75 x 10^{-5} lb / 10^6 Btu

Naphthalene = (307.6 x 10^6 Btu/hr) x (1.75 x 10^{-5} lb / 10^6 Btu)

Naphthalene = 5.38 x 10^{-3} lb/hr

Table B-9: Hazardous Air Pollutant Annual Emission Rates (2 SCCTs)

Annual hazardous air pollutant emission rates were determined based on the maximum pollutant hourly rates contained in Tables B-5 and B-8 for Case 4 (i.e., 59°F, 100% SCCT load) for Annual Profile #1 (3,500 hrs/yr natural gas) and Annual Profile #2 (3,000 hrs/yr natural gas and 500 hrs/yr ULSD fuel oil).

Example: Annual Profile #2

Natural Gas:

Naphthalene = (2.23 x 10^{-4} lb/hr) x (3,000 hr/yr) x (ton / 2,000 lb) x 2 SCCTs

Naphthalene = 6.68 x 10^{-4} ton/yr

ULSD Fuel Oil:

Naphthalene = (5.30 x 10^{-3} lb/hr) x (500 hr/yr) x (ton / 2,000 lb) x 2 SCCTs

Naphthalene = 2.65 x 10^{-3} ton/yr

Total Natural Gas + ULSD Fuel Oil

Naphthalene = 6.68 x 10^{-4} ton/yr + 2.65 x 10^{-3} ton/yr

Naphthalene = 3.32 x 10^{-3} ton/yr

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TableB-10: Annual Criteria and Sulfuric Acid Mist Pollutant Emission Rates – Annual Profile #1

Annual emission rates were determined from the pollutant hourly rates for Case 4 (59°F, 100% SCCT load, and assuming that each SCCT operates for 3,500 hours per year on natural gas. An example calculation for NO_x follows:

Example: NO_x

Case 4 NO_x Hourly Emission Rate = 32.0 lb/hr (per SCCT)

Annual NO_x = 32.0 lb/hr x 3,500 hrs/yr x ton/ 2000 lb x 2 SCCTs

Annual NO_x = 112.0 ton/yr

TableB-11: Annual Criteria and Sulfuric Acid Mist Pollutant Emission Rates – Annual Profile #2

Annual emission rates were determined from the pollutant hourly rates for Case 4 (59°F, 100% SCCT load, and assuming that each SCCT operates for 3,000 hours per year on natural gas and 500 hours per year on ULSD fuel oil. An example calculation for NO_x follows:

Example: NO_x

Natural Gas:

Case 4 NO_x Hourly Emission Rate = 32.0 lb/hr (per SCCT)

Annual NO_x = 32.0 lb/hr x 3,000 hrs/yr x ton/ 2000 lb x 2 SCCTs

Annual NO_x = 96.0 ton/yr

ULSD Fuel Oil:

Case 4 NO_x Hourly Emission Rate = 50.5 lb/hr (per SCCT)

Annual NO_x = 50.5 lb/hr x 500 hrs/yr x ton/ 2000 lb x 2 SCCTs

Annual NO_x = 25.7 ton/yr

Total Natural Gas + ULSD Fuel Oil

Annual NO_x = 96.0 ton/yr + 25.7 ton/yr

Annual NO_x = 121.7 ton/yr

Table B-12: SCCT Exhaust Data (Per SCCT), Natural Gas

Table B-12A.: Exhaust Molecular Weight (MW)

Exhaust gas compositions (volume %), exhaust flow rates (lb/sec), and exhaust temperatures (°F) shown in Table B-12A were obtained from the PWPS performance specification data.

1. Exhaust gas molecular weight was calculated by multiplying the exhaust composition (in volume % divided by 100) by the component molecular weight (in lb/lb-mole) and summing all components.

Example: Case 7 (90°F, 100% Load)

$$MW = [(0.842/100) \times 39.944] + [(70.8/100) \times 28.013] + [(12.6/100) \times 31.999] + [(3.27/100) \times 44.010] + [(12.45/100) \times 18.015]$$

$$MW = 27.88 \text{ lb/lb-mole}$$

2. Exhaust temperatures (in units of °K) were calculated by converting the PWPS exhaust temperatures (in units of °F)

Example: Case 8 (90°F, 75% Load)

PWPS Exhaust Temperature: 864 °F

Exhaust Temperature = (864 °F + 459.67) / (1.8)

Exhaust Temperature = 735 °K

3. Exhaust oxygen concentrations, dry were calculated by correcting the PWPS exhaust oxygen concentrations, wet, to dry conditions.

Example: Case 6 (59°F, 50% Load)

PWPS Exhaust Oxygen Concentration: 14.9 volume % (wet)

PWPS Exhaust Water Concentration: 8.05 volume %

Exhaust Oxygen Concentration (dry) = [(14.9) / (100 – 8.05)] x 100

Exhaust Oxygen Concentration = 16.20 volume % (dry)

Table B-12B.: Exhaust Flow Rates Data

Exhaust gas flow rates (actual, standard, and actual at 15% O_2, dry) were calculated based on the PWPS data shown in Table B12A. Stack diameter was provided by TEC. Stack exit velocity was calculated based on the exhaust flow rates and calculated stack area.

1. Exhaust gas flow rates, in units of actual cubic feet per minute, were calculated based on the PWPS exhaust flow rates (in units of lb/sec) and molecular weights shown in Table B-12A and the Ideal Gas Law.

Example: Case 1 (20°F, 100% Load)

PWPS Exhaust Flow Rate: 212.0 lb/sec (from Table B-12A)

Exhaust Gas Molecular Weight: 28.22 lb/lb-mole (from Table B-12A)

PWPS Exhaust Gas Temperature: 828 °F (from Table B-12A)

Volume of one lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (acfm) = (212.0 lb/sec) x (60 sec/min) x (lb-mole / 28.22 lb) x (385.3 ft^3/lb-mole) x [(828 + 460) / (68 + 460)]

Exhaust Gas Flow Rate = 423,625 acfm

2. Stack area was calculated based on the stack exit diameter provided by TEC.

Example: All Cases

Stack Exit Diameter: 9.5 ft; 2.896 m

Stack Exit Area = π x (9.5 ft / 2)^2

Stack Exit Area = 70.88 ft^2; 6.59 m^2

3. Stack exit velocities were calculated by dividing the calculated actual exhaust flow rate by the stack exit area.

Example: Case 3 (20°F, 50% Load)

Calculated Actual Exhaust Flow Rate: 287,770 ft^3/min (From Table B-12B)

Calculated Stack Exit Area: 70.88 ft^2

Stack Exit Velocity = (287,770 ft^3/min) x (1 min / 60 sec) x (1 / 70.88 ft^2)

Stack Exit Velocity = 67.7 ft/sec; 20.6 m/sec

4. Exhaust gas flow rates, in units of dry, standard (at 68 °F) actual cubic feet per minute, were calculated based on the PWPS exhaust flow rates (in units of lb/sec), moisture contents, and molecular weights shown in Table B-12A and the Ideal Gas Law.

Example: Case 7 (90°F, 100% Load)

PWPS Exhaust Flow Rate: 192.0 lb/sec (from Table B-12A)

PWPS Exhaust Gas Moisture Content: 12.45 volume % (from Table B-12A)

Exhaust Gas Molecular Weight: 27.88 lb/lb-mole (From Table B-12A)

Volume of One lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (dscfm) = (192.0 lb/sec) x (60 sec / min) x (lb-mole / 27.88 lb) x (385.3 ft^3/lb-mole) x [1 - (12.45 / 100)]

Exhaust Gas Flow Rate = 139,366 dscfm

5 Exhaust gas flow rates, in units of dry, standard cubic feet per minute corrected to 15% O_2, were calculated by correcting the standard dry exhaust flow rate (dscfm) to 15% O_2.

Example: Case 9 (90°F, 50% Load)

Exhaust Flow Rate: 105,847 dscfm (from Table B-12B)

Calculated Exhaust Oxygen Content: 16.0 volume % (dry) (from Table B-12A)

Atmospheric Oxygen Content: 20.9 volume %

Exhaust Gas Flow Rate (dscfm @ 15% O_2) = (105,847 dscfm) x [(20.9 – 16.0) / (20.9 – 15.0)]

Exhaust Gas Flow Rate = 87,907 dscfm @ 15% O_2

Table B-13: Fuel Flow Rate Data (Per SCCT) - Natural Gas

Data shown in Table B-13 is based on PWPS fuel flow rates, and the heat content and density of natural gas. The PWPS fuel rate (lb/hr) as shown on the table has been adjusted to include a 7 % margin. The heat input values and conversions to other fuel rate units have been derived from the adjusted PWPS fuel rate.

Example: Case 5 (59°F, 75% load)

PWPS fuel rate = 10,827 lb/hr

Adjusted fuel rate = 10,827 lb/hr x 1.07 = 11,585 lb/hr

Natural Gas Density = 0.0451 lb/ft^3

Natural Gas Heat Content: 20,671 Btu/lb (LHV)

Natural Gas Heat Content: 22,933 Btu/lb (HHV)

Heat Input (LHV) = 11,585 lb/hr x 20,671 Btu/lb x (1/10^6) = 239.5 MMBtu/hr

Heat Input (HHV) = 11,585 lb/hr x 22,933 Btu/lb x (1/10^6) = 265.7 MMBtu/hr

Fuel Rate = 11,585 lb/hr / 0.0451 lb/ft^3 x (1/10^6) = 0.257 10^6 ft^3/hr

Fuel Rate = 11,585 lb/hr x hr/3,600 sec = 3.218 lb/sec

Table B-14: SCCT Exhaust Data (Per SCCT), ULSD Fuel Oil

Table B-14A.: Exhaust Molecular Weight (MW)

Exhaust gas compositions (volume %), exhaust flow rates (lb/sec), and exhaust temperatures (°F) shown in Table B-14A were obtained from the PWPS performance specification data.

1. Exhaust gas molecular weight was calculated by multiplying the exhaust composition (in volume % divided by 100) by the component molecular weight (in lb/lb-mole) and summing all components.

Example: Case 8 (90°F, 75% Load)

MW = [(0.857/100) x 39.944] + [(72.0/100) x 28.013] + [(13.6/100) x 31.999]
+ [(3.97/100) x 44.010] + [(9.57/100) x 18.015]

MW = 28.34 lb/lb-mole

2. Exhaust temperatures (in units of °K) were calculated by converting the PWPS exhaust temperatures (in units of °F)

Example: Case 8 (90°F, 75% Load)

PWPS Exhaust Temperature: 872 °F

Exhaust Temperature = (872 °F + 459.67) / (1.8)

Exhaust Temperature = 740 °K

3. Exhaust oxygen concentrations, dry were calculated by correcting the PWPS exhaust oxygen concentrations, wet, to dry conditions.

Example: Case 6 (59°F, 50% Load)

PWPS Exhaust Oxygen Concentration: 15.2 volume % (wet)

PWPS Exhaust Water Concentration: 6.31 volume %

Exhaust Oxygen Concentration (dry) = [(15.2) / (100 – 6.31)] x 100

Exhaust Oxygen Concentration = 16.22 volume % (dry)

Table B-14B.: Exhaust Flow Rates Data

Exhaust gas flow rates (actual, standard, and actual at 15% O_2, dry) were calculated based on the PWPS data shown in Table B14A. Stack diameter was provided by TEC. Stack exit velocity was calculated based on the exhaust flow rates and calculated stack area.

1. Exhaust gas flow rates, in units of actual cubic feet per minute, were calculated based on the PWPS exhaust flow rates (in units of lb/sec) and molecular weights shown in Table B-14A and the Ideal Gas Law.

Example: Case 1 (20°F, 100% Load)

PWPS Exhaust Flow Rate: 205.0 lb/sec (from Table B-14A)

Exhaust Gas Molecular Weight: 28.65 lb/lb-mole (from Table B-14A)

PWPS Exhaust Gas Temperature: 793 °F (from Table B-14A)

Volume of one lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (acfm) = (205.0 lb/sec) x (60 sec/min) x (lb-mole / 28.65 lb)
x (385.3 ft^3/lb-mole) x [(793 + 460) / (68 + 460)]

Exhaust Gas Flow Rate = 392,572 acfm

2. Stack area was calculated based on the stack exit diameter provided by TEC.

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Example: All Cases

Stack Exit Diameter: 9.5 ft; 2.896 m

Stack Exit Area = π x (9.5 ft / 2)^2

Stack Exit Area = 70.88 ft^2; 6.59 m^2

3. Stack exit velocities were calculated by dividing the calculated actual exhaust flow rate by the stack exit area.

Example: Case 3 (20°F, 50% Load)

Calculated Actual Exhaust Flow Rate: 271,983 ft^3/min (From Table B-14B)

Calculated Stack Exit Area: 70.88 ft^2

Stack Exit Velocity = (271,983 ft^3/min) x (1 min / 60 sec) x (1 / 70.88 ft^2)

Stack Exit Velocity = 64.0 ft/sec; 19.5 m/sec

4. Exhaust gas flow rates, in units of dry, standard (at 68 °F) actual cubic feet per minute, were calculated based on the PWPS exhaust flow rates (in units of lb/sec), moisture contents, and molecular weights shown in Table B-14A and the Ideal Gas Law.

Example: Case 7 (90°F, 100% Load)

PWPS Exhaust Flow Rate: 190.0 lb/sec (from Table B-14A)

PWPS Exhaust Gas Moisture Content: 10.63 volume % (from Table B-14A)

Exhaust Gas Molecular Weight: 28.27 lb/lb-mole (From Table B-14A)

Volume of One lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (dscfm) = (190.0 lb/sec) x (60 sec / min) x (lb-mole / 28.27 lb)
x (385.3 ft^3/lb-mole) x [1 - (10.63 / 100)]

Exhaust Gas Flow Rate = 138,864 dscfm

5 Exhaust gas flow rates, in units of dry, standard cubic feet per minute corrected to 15% O_2, were calculated by correcting the standard dry exhaust flow rate (dscfm) to 15% O_2.

Example: Case 9 (90°F, 50% Load)

Exhaust Flow Rate: 105,804 dscfm (from Table B-14B)

Calculated Exhaust Oxygen Content: 15.84 volume % (dry) (from Table B-14A)

Atmospheric Oxygen Content: 20.9 volume %

Exhaust Gas Flow Rate (dscfm @ 15% O_2) = (105,804 dscfm) x [(20.9 – 15.84) / (20.9 – 15.0)]

Exhaust Gas Flow Rate = 90,770 dscfm @ 15% O_2

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Table B-15 Fuel Flow Rate Data (Per SCCT) – ULSD Fuel Oil

Data shown in Table B-15 is based on PWPS ULSD fuel flow rates and ULSD heat content and density. The PWPS fuel rate (lb/hr) as shown on the table has been adjusted to include a 7 % margin. The heat input values and conversions to other fuel rate units have been derived from the adjusted PWPS fuel rate.

Example: Case 5 (59°F, 75% load)

PWPS fuel rate = 11,409 lb/hr

Adjusted fuel rate = 11,409 lb/hr x 1.07 = 12,208 lb/hr

ULSD Fuel Oil Heat Content: 18,360 Btu/lb (LHV)

ULSD Fuel Oil Heat Content: 19,553 Btu/lb (HHV)

ULSD Fuel Oil Density: 6.81 lb/gal

Heat Input (LHV) = 12,208 lb/hr x 18,360 Btu/lb x ($1/10^6$) = 224.1 MMBtu/hr

Heat Input (HHV) = 12,208 lb/hr x 19,553 Btu/lb x ($1/10^6$) = 238.7 MMBtu/hr

Fuel Rate = 12,208 lb/hr / 6.81 lb/gal x ($1/10^3$) = 1.793 10^3 gal/hr

Fuel Rate = 12,208 lb/hr x hr/3,600 sec = 3.391 lb/sec

Table B-16: Emergency Diesel Engines, Criteria Pollutant Emission Rates

The emission rates in units of g/hp-hr for NO_x, CO, VOC, and PM were provided by the vendor. The horsepower was derived from the electrical output rating (kWe) of the engine. The emission rates for SO_2 were derived from the fuel flow, density, and fuel sulfur content information, which were also provided.

Example: Derivation of Horsepower

Electrical Output Rating = 800 kWe
Assumed Efficiency = 80%

Horsepower = 800 kWe x (1/(80/100)) x hp/0.7457 kW = 1,340 hp

Example: Criteria Pollutant Calculation for NO_x

NO_x Emission Rate = 5.26 g/hp-hr
Operating Hours = 100 hr/yr

NO_x (lb/hr) = 5.26 g/hp-hr x 0.002204 lb/g x 1,340 hp =15.5 lb/hr

NO_x (ton/yr) = 15.5 lb/hr x 100 hr/yr x ton/2,000 lb = 0.78 ton/yr

Example: Calculation of SO_2 Emissions

Maximum Fuel Flow = 57.2 gal/hr

Fuel Sulfur Content = 0.0015 wt % S (for ULSD fuel oil)

Fuel Density = 7.08 lb/gal

SO_2 (lb/hr) = 57.2 gal/hr x 7.08 lb/gal x 0.0015 % S/100% x 2 lb SO_2/1lb S = 0.012 lb/hr

SO_2 (ton/yr) = 0.012 lb/hr x 100 hr/yr x ton/2,000 lb = 0.0006 ton/yr
SO_2 (g/hp-hr) = 0.012 lb/hr x g/0.0022046 lb x 1/ 1,340 hp = 0.004 g/hp-hr

Table B-17: Emergency Diesel Engines, Hazardous Air Pollutant Emission Rates

The HAPs were based on EPA AP-42 emission factors (Section 3 Table 3.3-2), and the information supplied by the vendor.

Example: Calculation of Formaldehyde Emissions

Maximum Fuel Flow = 57.2 gal/hr

Fuel Heat Content = 138,000 Btu/gal (HHV)

AP-42 Formaldehyde Emission Factor = 0.00118 lb/MMBtu

Operating Hours = 100 hr/yr

Engine Heat Input = 57.2 gal/hr x 138,000 Btu/gal x ($1/10^6$) = 7.89 MMBtu/hr

Formaldehyde (lb/hr) = 0.00118 lb/MMBtu x 7.89 MMBtu/hr = 0.00931 lb/hr

Formaldehyde (ton/yr) = 0.00931 lb/hr x 100 hr/yr x ton/2,000 lb = 0.000466 ton/yr

Table B-18: SCCT Stack Parameters – Natural Gas

The data in this table is also provided in Table B-12. The exhaust velocities and temperatures are shown to more decimal places, but their derivation was previously described.

Table B-19: SCCT Stack Parameters – ULSD Fuel Oil

The data in this table is also provided in Table B-14. The exhaust velocities and temperatures are shown to more decimal places, but their derivation was previously described.

Table B-20: Emergency Diesel Engines, Stack Parameters

The stack height, diameter, flow rate, and exhaust temperature were provided by the vendor. Examples of the conversions, e.g., feet to meters, and the derivation of stack area and exit velocity have previously been given for Table B-12.

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LIST OF ACRONYMS

°F	degrees Fahrenheit
°K	degrees Kelvin
%	percent
acfm	actual cubic feet per minute
AP-42	EPA's Compilation of Air Pollutant Emission Factors, 5th Edition
Btu	British thermal unit
Btu/hr	British thermal units per hour
CO	carbon monoxide
CO_2	carbon dioxide
SCCT	simple cycle combustion turbine
dscfm	dry standard cubic feet per minute
EPA	United States Environmental Protection Agency
ft	feet
ft^2	square feet
ft^3	cubic feet
ft/sec	feet per second
ft^3/min	cubic feet per minute
ft^3/lb-mole	cubic feet per pound mole
gal/hr	gallons per hour
g	gram
g/hp-hr	grams per horsepower hour
g/s	grams per second
gr	grain
gr S	grains of sulfur
gr S/100 ft^3	grains of sulfur per 100 cubic feet
H_2SO_4	sulfuric acid, or sulfuric acid mist
HAP	hazardous air pollutant
HHV	higher heating value
hp	horsepower
hr	hour
hr/yr	hours per year
kW	kilowatt
kWe	kilowatts electric
lb	pounds
lb/ft^3	pounds per cubic feet
lb/gal	pounds per gallon
lb/hr	pounds per hour
lb/sec	pounds per second
LHV	lower heating value
lb/MMBtu	pounds per million British thermal units
MMBtu/hr	million British thermal units per hour
lb-mole	pound mole
lb/lb-mole	pound per pound mole
lb/sec	pound per second
m	meter
m^2	square meters
m/sec	meters per second
min	minute
NG	natural gas
NO_x	nitrogen oxides
O_2	oxygen
PWPS	Pratt & Whitney Power Systems
Pb	lead

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PM	particulate matter
PM_{10}	particulate matter less than 10 microns in aerodynamic diameter
ppmvd	parts per million by volume, dry
S	sulfur
sec	second
sec/min	seconds per minute
SO_2	sulfur dioxide
TEC	Tampa Electric Company
ton/yr	ton per year
ULSD	ultra low sulfur diesel
VOC	volatile organic compound
wt % S	weight percent sulfur
yr	year

ATTACHMENT 4

RESPONSE TO EPC-4

TECHNICAL DATA FOR CATERPILLAR C27 TA
EMERGENCY GENERATOR DIESEL ENGINE

DIESEL GENERATOR SET

CATERPILLAR®

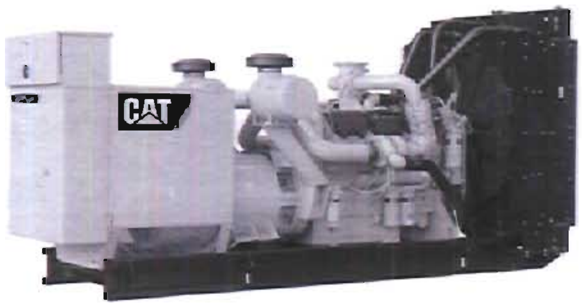

Image shown may not reflect actual package.

STANDBY
800 ekW 1000 kVA
60 Hz 1800 rpm 480 Volts

Caterpillar is leading the power generation marketplace with Power Solutions engineered to deliver unmatched flexibility, expandability, reliability, and cost-effectiveness.

FEATURES

FUEL/EMISSIONS STRATEGY
- EPA Tier 2

DESIGN CRITERIA
- The generator set accepts 100% rated load in one step per NFPA 110 and meets ISO 8528-5 transient response.

UL 2200
- UL 2200 listed packages available. Certain restrictions may apply. Consult with your Caterpillar Dealer.

FULL RANGE OF ATTACHMENTS
- Wide range of bolt-on system expansion attachments, factory designed and tested

SINGLE-SOURCE SUPPLIER
- Fully prototype tested with certified torsional vibration analysis available

WORLDWIDE PRODUCT SUPPORT
- Caterpillar® dealers provide extensive post sale support including maintenance and repair agreements
- Caterpillar dealers fill 99.7% of parts orders within 24 hours
- Caterpillar dealers have over 1,600 dealer branch stores operating in 200 countries
- The Cat® S•O•S℠ program cost effectively detects internal engine component condition, even the presence of unwanted fluids and combustion by-products

CAT C27 ATAAC DIESEL ENGINE
- Utilizes ACERT™ Technology
- Reliable, rugged, durable design
- Four-cycle diesel engine combines consistent performance and excellent fuel economy with minimum weight
- Electronic engine control

CAT SR4B GENERATOR
- Designed to match the performance and output characteristics of Caterpillar diesel engines
- Single point access to accessory connections
- UL 1446 recognized Class H insulation

CAT EMCP 3 SERIES CONTROL PANELS
- Simple user friendly interface and navigation
- Scalable system to meet a wide range of customer needs
- Integrated Control System and Communications Gateway

FACTORY INSTALLED STANDARD & OPTIONAL EQUIPMENT

System	Standard	Optional
Air Inlet	• Single element canister type air cleaner • Service indicator	• Dual element air cleaners • Air inlet adapters
Cooling	• Radiator with guard (50°C) • Low profile (frontal area) • Low airflow • Coolant drain line with valve • Fan and belt guards • Caterpillar Extended Life Coolant • Coolant level sensors • ATAAC • Duct Flange	• Jacket water heater with shutoff valves
Exhaust	• Dry exhaust manifold • Flanged faced outlets	• Stainless steel exhaust flex fittings • Elbows, flanges, expanders & Y adapters
Fuel	• Primary fuel filter with water separator • Secondary fuel filter • Fuel priming pump • Flexible fuel lines (terminated on base) • Fuel pressure gauge	
Generators	• SR4B Self Excited • Class H insulation • Class F temperature (105°C prime/130°C standby) • Winding temperature detectors (select models) • Anti-condensation space heaters • Power Terminal Strip • Random Wound • Optimum winding pitch	• Oversize & premium generators • Permanent magnet
Power Termination	• Bus bar (NEMA hole connections)a • Bottom cable entry • AC & DC customer wiring area	• Circuit breakers, UL listed, 3 pole with shunt trip, 80% rated
Governor	• ADEM™ A4	
Control Panels	• User Interface panel (UIP) - rear mount • EMCP 3.1 generator set controller • Speed adjust • AC & DC customer wiring area (right side) • CAT Digital Voltage Regulator (CDVR) with KVAR/PF control, 3-phase sensing • Emergency Stop Push button	• EMCP 3.2 and EMCP 3.3 • Option for right or left mount UIP • Option for rear or left mount Customer wiring area • Local & remote annunciator modules • Discrete I/0 Module • Generator temperature monitoring & protection • Voltage raise/lower switch
Lube	• Lubricating oil and filter • Oil drain line with valves • Fumes disposal • Gear type lube oil pump	
Mounting	• Structual steel tube • Anti-vibration mounts	
Starting/Charging	• 24 volt starting motor(s) • Batteries with rack and cables • Battery disconnect	• Battery chargers (10 Amp) • 45 amp charging alternator • Oversize batteries • Ether starting aid
General	• Right-hand service • Paint - Caterpillar Yellow (except rails and radiators gloss black) • SAE standard rotation • Flywheel and Flywheel housing - SAE No. 0	• UL 2200 • CSA certification • EU Declaration of Incorporation • EEC Declaration of Conformity

STANDBY 800 ekW 1000 kVA

60 Hz 1800 rpm 480 Volts

CATERPILLAR®

SPECIFICATIONS

CAT GENERATOR

SR4B Generator
Frame size.. 597
Excitation.. Self Excited
Pitch.. 0.8000
Number of poles.. 4
Number of bearings.. Single Bearing
Number of Leads.. 12
Insulation........................ UL 1446 Recognized Class H with tropicalization and antiabrasion
IP rating.. Drip Proof IP22
Alignment.. Close Coupled
Overspeed capability - % of rated.. 150
Wave form.. Less than 5% deviation
Paralleling kit/Droop transformer.. Standard
Voltage regulator.3 Phase sensing with selectible volts/Hz
Voltage regulation............Less than +/- 1/2% (steady state)
Less than +/- 1% (no load to full load)
Telephone Influence Factor.. Less than 50
Harmonic distortion.. Less than 5%

CAT DIESEL ENGINE

C27 TA, V-12, 4-stroke-cycle watercooled diesel
Bore - mm.. 137.20 mm (5.4 in)
Stroke - mm.. 152.40 mm (6.0 in)
Displacement - L.. 27.03 L (1649.47 in³)
Compression ratio.. 16.5:1
Aspiration.. TA
Fuel system.. MEUI
Governor type.. ADEM™ A4

CAT EMCP 3 SERIES CONTROLS

• EMCP 3 (Standard)
•Integral to generator terminal box
•Single location for customer connection
•IP 23 enclosure
• 24 Volt DC Control
• UL/CSA/CE/UL508A
• Lockable hinged door (option)
• Run/Auto/Stop control
• True RMS metering, 3-phase
•Speed Adjust
• Voltage adjust (optional on 3.1)
• Digital indications for:
  - RPM
  - Operating hours
  - Oil pressure
  - Coolant temperature
- Low Coolant Level
  - System DC volts
  - L-L volts, L-N volts, phase amps, Hz
- ekW, kVA, kVAR, kW-hr, %kW, PF(*)
• Shutdowns with indicating lights (with optional annunciator):
  - Low oil pressure
  - High coolant temperature
  - Overspeed
  - Emergency stop
  - Failure to start (overcrank)
• Programmable protective relaying functions (*):
  - Under and over voltage
  - Under and over frequency
  - Reverse power
  - Overcurrent (phase & total)
• MODBUS isolated data link (RS-485 half-duplex) supports serial communication at data rate up to 115.2 kbaud (*)
(*) Requires EMCP 3.2 & EMCP 3.3

STANDBY 800 ekW 1000 kVA

60 Hz 1800 rpm 480 Volts

CATERPILLAR®

TECHNICAL DATA

Open Generator Set - - 1800 rpm/60 Hz/480 Volts	DM7696	
EPA Certified Tier 2		
Generator Set Package Performance		
Genset Power rating @ 0.8 pf	1000 kVA	
Genset Power rating with fan	800 ekW	
Coolant to aftercooler temp max		
Coolant to aftercooler temp max	49 ° C	120 ° F
Fuel Consumption		
100% load with fan	216.6 L/hr	57.2 Gal/hr
75% load with fan	171.6 L/hr	45.3 Gal/hr
50% load with fan	122.2 L/hr	32.3 Gal/hr
Cooling System[1]		
Air flow restriction (system)	0.12 kPa	0.48 in. water
Air flow (max @ rated speed for radiator arrangement)	1137 m³/min	40153 cfm
Engine Coolant capacity with radiator/exp. tank	160.0 L	42.3 gal
Engine coolant capacity	55.0 L	14.5 gal
Radiator coolant capacity	105.0 L	27.7 gal
Inlet Air		
Combustion air inlet flow rate	61.5 m³/min	2171.9 cfm
Exhaust System		
Exhaust stack gas temperature	512.8 ° C	955.0 ° F
Exhaust gas flow rate	171.2 m³/min	6045.9 cfm
Exhaust flange size (internal diameter)	203 mm	8 in
Exhaust system backpressure (maximum allowable)	10.0 kPa	40.2 in. water
Heat Rejection		
Heat rejection to coolant (total)	330 kW	18767 Btu/min
Heat rejection to exhaust (total)	767 kW	43619 Btu/min
Heat rejection to aftercooler	157 kW	8929 Btu/min
Heat rejection to atmosphere from engine	164 kW	9327 Btu/min
Heat rejection to atmosphere from generator	36.8 kW	2092.8 Btu/min
Alternator[2]		
Motor starting capability @ 30% voltage dip	2131 skVA	
Frame	597	
Temperature Rise	130 ° C	234 ° F
Lube System		
Sump refill with filter	68.0 L	18.0 gal
Emissions (Nominal)[3]		
NOx g/hp-hr	5.26 g/hp-hr	
CO g/hp-hr	.23 g/hp-hr	
HC g/hp-hr	.03 g/hp-hr	
PM g/hp-hr	.024 g/hp-hr	

[1] For ambient and altitude capabilities consult your Caterpillar dealer. Air flow restriction (system) is added to existing restriction from factory.

[2] UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics. Generator temperature rise is based on a 40°C ambient per NEMA MG1-32.

[3] Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NOx. Data shown is based on steady state operating conditions of 77°F, 28.42 in HG and number 2 diesel fuel with 35° API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

RATING DEFINITIONS AND CONDITIONS

Meets or Exceeds International Specifications: AS1359, CSA, IEC60034, ISO3046, ISO8528, NEMA MG 1-33, UL508A, 98/37/EC

Standby - Output available with varying load for the duration of the interruption of the normal source power. Average power output is 70% of the standby power rating. Typical operation is 200 hours per year, with maximum expected usage of 500 hours per year. Standby power in accordance with ISO8528. Fuel stop power in accordance with ISO3046. Standby ambients shown indicate ambient temperature at 100% load which results in a coolant top tank temperature just below the shutdown temperature.

Ratings are based on SAE J1995 standard conditions. These ratings also apply at ISO3046,standard conditions.

Fuel Rates are based on fuel oil of 35° API [16° C (60° F)] gravity having an LHV of 42 780 kJ/kg (18,390 Btu/lb) when used at 29° C (85° F) and weighing 838.9 g/liter (7.001 lbs/U.S. gal.). Additional ratings may be available for specific customer requirements, contact your Caterpillar representative for details. For information regarding Low Sulfur fuel and Biodiesel capability, please consult your Caterpillar dealer.

DIMENSIONS

Package Dimensions		
Length	4668.7 mm	183.81 in
Width	1904.6 mm	74.98 in
Height	2080.5 mm	81.91 in
Weight	6373 kg	14,050 lb

Note: Do not use for installation design.
See general dimension drawings for detail (Drawing #3071564).

Performance No.: DM7696

Feature Code:: C27DE33

Source:: U.S. Sourced

September 20 2007 11076195

ATTACHMENT 5

RESPONSE TO EPC-3

REVISED APPENDIX B EMISSION RATE CALCULATIONS
TABLES B-1, B-3, B-8, B-13, and B-15

Table B-1. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Annual Emission Rate Summary

Pollutant	Potential Annual Emissions (ton/yr)		
	PWPS CTs (2 CTs)[1]	Emergency Diesel Engine	Project Totals
Criteria Pollutants			
NO_x	121.7	0.8	**122.4**
CO	16.5	0.034	**16.5**
VOC	4.7	0.0044	**4.7**
SO_2	6.6	0.00061	**6.6**
PM_{10} (filterable + condensable)	11.3	0.0035	**11.3**
Pb	0.0006	Neg.	**0.00062**
Hazardous Air Pollutants			
Formaldhyde[2]	0.4	Neg.	**0.4**
Total HAPs	0.6	Neg.	**0.6**
Other Pollutants			
H_2SO_4 Mist	0.8	Neg.	**0.8**
PM (filterable)[3]	11.3	0.0035	**11.3**
Other Constituents			
CO_2	136,865	65	**136,930**

N/A - not applicable
Neg. - negligible

[1] Maximum of Annual Profile 1 (3,500 hrs/yr/CT natural gas)
or Annual Profile 2 (3,000 hrs/yr/CT natural gas + 500 hrs/yr/CT ULSD fuel oil).
[2] Maximum individual HAP.
[3] For PWPS CTs, all PM is $PM_{2.5}$ or less. PM (filterable) is assumed to be 50% of total PM.

Sources: ECT, 2008.
PWPS, 2008.
TEC, 2008.

Table B-3. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Hourly PM/PM_{10}, SO_2, H_2SO_4 Mist, and Pb Emission Rates (Per CT) - Natural Gas

Temp. (°F)	Case	Load (%)	PM/PM_{10}[1] (lb/hr)	PM/PM_{10}[1] (g/sec)	SO_2[2] (lb/hr)	SO_2[2] (g/sec)	H_2SO_4[3] (lb/hr)	H_2SO_4[3] (g/sec)	Lead[4] (lb/hr)	Lead[4] (g/sec)
20	1-Gas	100	2.5	0.32	1.87	0.24	0.21	0.027	0.00017	0.000021
	2-Gas	75	2.5	0.32	1.45	0.18	0.17	0.021	0.00013	0.000016
	3-Gas	50	2.5	0.32	1.06	0.13	0.12	0.015	0.00009	0.000012
59	4-Gas	100	2.5	0.32	1.89	0.24	0.22	0.027	0.00017	0.000021
	5-Gas	75	2.5	0.32	1.47	0.19	0.17	0.021	0.00013	0.000016
	6-Gas	50	2.5	0.32	1.08	0.14	0.12	0.016	0.00010	0.000012
90	7-Gas	100	2.5	0.32	1.79	0.23	0.21	0.026	0.00016	0.000020
	8-Gas	75	2.5	0.32	1.41	0.18	0.16	0.020	0.00012	0.000016
	9-Gas	50	2.5	0.32	1.04	0.13	0.12	0.015	0.00009	0.000012
		Maximums	**2.5**	**0.32**	**1.89**	**0.24**	**0.22**	**0.027**	**0.00017**	**0.000021**

[1] Total particulate matter as measured by EPA RM 201 or 201A, and 202.
[2] Based on natural gas sulfur content of 2.0 gr/100 ft^3.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] Lead emission factor, EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-2., July 1998.

Sources: ECT, 2008.
PWPS, 2008.

Table B-8. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Hazardous Air Pollutant Hourly Emission Rates - ULSD (Per CT)

Parameter			Units	Value								
Scenario			N/A	1-O	2-O	3-O	4-O	5-O	6-O	7-O	8-O	9-O
Maximum CT Hourly Fuel Flow:			10^6 Btu/hr (HHV)	296.2	233.9	173.0	302.7	238.7	176.4	307.6	242.7	179.1
Hazardous Air Pollutant	**No. 2 FO Metals Concentration[1] (ppbw)**	**No. 2 FO Metals Concentration[2] (ppbw)**	**Oil Emission Factor[3,4,5,6] (lb/10^6 Btu)**	**Hourly Emissions**								
				1-O (lb/hr)	**2-O (lb/hr)**	**3-O (lb/hr)**	**4-O (lb/hr)**	**5-O (lb/hr)**	**6-O (lb/hr)**	**7-O (lb/hr)**	**8-O (lb/hr)**	**9-O (lb/hr)**
1,3-Butadiene			8.00E-06	2.37E-03	1.87E-03	1.38E-03	2.42E-03	1.91E-03	1.41E-03	2.46E-03	1.94E-03	1.43E-03
Acetaldehyde												
Acrolein												
Arsenic (As)	N/A	<DL	1.10E-05	3.26E-03	2.57E-03	1.90E-03	3.33E-03	2.63E-03	1.94E-03	3.38E-03	2.67E-03	1.97E-03
Benzene			2.75E-05	8.15E-03	6.43E-03	4.76E-03	8.33E-03	6.56E-03	4.85E-03	8.46E-03	6.67E-03	4.92E-03
Beryllium (Be)	N/A	N/A	3.10E-07	9.18E-05	7.25E-05	5.36E-05	9.38E-05	7.40E-05	5.47E-05	9.53E-05	7.52E-05	5.55E-05
Cadmium (Cd)	N/A	<DL	4.80E-06	1.42E-03	1.12E-03	8.30E-04	1.45E-03	1.15E-03	8.47E-04	1.48E-03	1.16E-03	8.60E-04
Chromium (Cr)	31.0	242.4	1.24E-05	3.67E-03	2.90E-03	2.14E-03	3.75E-03	2.96E-03	2.19E-03	3.81E-03	3.01E-03	2.22E-03
Ethylbenzene												
Formaldehyde			1.75E-05	5.18E-03	4.09E-03	3.03E-03	5.30E-03	4.18E-03	3.09E-03	5.38E-03	4.25E-03	3.13E-03
Lead (Pb)	5.3	15.0	7.67E-07	2.27E-04	1.79E-04	1.33E-04	2.32E-04	1.83E-04	1.35E-04	2.36E-04	1.86E-04	1.37E-04
Manganese (Mn)	1.9	5.5	2.81E-07	8.33E-05	6.58E-05	4.87E-05	8.52E-05	6.71E-05	4.96E-05	8.65E-05	6.83E-05	5.04E-05
Mercury (Hg)	<DL	N/A	1.20E-06	3.55E-04	2.81E-04	2.08E-04	3.63E-04	2.86E-04	2.12E-04	3.69E-04	2.91E-04	2.15E-04
Naphthalene			1.75E-05	5.18E-03	4.09E-03	3.03E-03	5.30E-03	4.18E-03	3.09E-03	5.38E-03	4.25E-03	3.13E-03
Nickel (Ni)	2.0	28.9	1.48E-06	4.38E-04	3.46E-04	2.56E-04	4.47E-04	3.53E-04	2.61E-04	4.55E-04	3.59E-04	2.65E-04
Polycyclic Aromatic Hydrocarbons			2.00E-05	5.92E-03	4.68E-03	3.46E-03	6.05E-03	4.77E-03	3.53E-03	6.15E-03	4.85E-03	3.58E-03
Propylene Oxide												
Selenium (Se)	1.9	<DL	9.72E-08	2.88E-05	2.27E-05	1.68E-05	2.94E-05	2.32E-05	1.71E-05	2.99E-05	2.36E-05	1.74E-05
Toluene												
Xylene												
Maximum Individual HAP				**0.008**	**0.006**	**0.005**	**0.008**	**0.007**	**0.005**	**0.008**	**0.007**	**0.005**
Total HAPs				**0.036**	**0.029**	**0.021**	**0.037**	**0.029**	**0.022**	**0.038**	**0.030**	**0.022**

N/A - not available <DL - less than detection limit ppbw - parts per billion, by weight

[1] - Analysis of Motor-Vehicle Fuels for Metals by Inductively Coupled Plasma-Mass Spectrometry, University of Iowa, 2000.
[2] - Survey of Ultra-Trace Metals in Gas Turbine Fuels, Siemens Westinghouse Power Corporation & Texas Oil Tech Laboratories, October 2004.
[3] - Organic pollutant emission factors reduced by 50% percent due to use of oxidation catalyst.
[4] - Organic emission factors, EPA AP-42, Stationary Gas Turbines, Table 3.1-4., April 2000.
[5] - Metallic emission factors for As, Be, Cd, and Hg; EPA AP-42, Stationary Gas Turbines, Table 3.1-5., April 2000.
[6] - Metallic emission factors for Cr, Pb, Mn, Ni, and Se; higher of University of Iowa and Siemens Westinghouse data.

Sources: ECT, 2008.
PWPS, 2008.

Table B-13. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
CT Fuel Flow Rate Data (Per CT) - Natural Gas*

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1-Gas	4-Gas	7-Gas	2-Gas	5-Gas	8-Gas	3-Gas	6-Gas	9-Gas
Heat Input - LHV (MMBtu/hr)	305.2	308.9	291.4	236.1	239.5	229.4	173.6	175.9	169.1
Heat Input - HHV (MMBtu/hr)	338.6	342.7	323.3	261.9	265.7	254.5	192.6	195.2	187.6
Fuel Rate (lb/hr)	14,763	14,945	14,099	11,420	11,585	11,097	8,396	8,511	8,182
Fuel Rate (10^6 ft^3/hr)	0.328	0.332	0.313	0.253	0.257	0.246	0.186	0.189	0.182
Fuel Rate (lb/sec)	4.101	4.151	3.916	3.172	3.218	3.082	2.332	2.364	2.273

*Includes 7.0-percent margin.

Sources: ECT, 2008.
PWPS, 2008.

Table B-15. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
CT Fuel Flow Rate Data (Per CT) - ULSD Fuel Oil*

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1-ULSD	4-ULSD	7-ULSD	2-ULSD	5-ULSD	8-ULSD	3-ULSD	6-ULSD	9-ULSD
Heat Input - LHV (MMBtu/hr)	278.2	284.3	288.8	219.6	224.1	227.9	162.4	165.6	168.1
Heat Input - HHV (MMBtu/hr)	296.2	302.7	307.6	233.9	238.7	242.7	173.0	176.4	179.1
Fuel Rate (lb/hr)	15,150	15,483	15,730	11,960	12,208	12,411	8,846	9,020	9,158
Fuel Rate (10^3 gal/hr)	2.225	2.274	2.310	1.756	1.793	1.823	1.299	1.325	1.345
Fuel Rate (lb/sec)	4.208	4.301	4.369	3.322	3.391	3.447	2.457	2.506	2.544

*Includes 7.0-percent margin.

Sources: ECT, 2008.
PWPS, 2008.

FT8-3 Swift Pac (with CO Converter)
Sheet-1, Notes Applicable to Performance and Emissions Data
Tampa-Electric

Perf_CustCpy_Tampa_Electric_FT8-3_AS_R3-012508.xls

Notes:

0. All Performance/Emissions Data submitted are subject to the sum of the following notes.
1. The Swift Pac (SP) consists of two turbines driving a common generator. Rates are shown as per GT, and per Swift Pac (2-GT's).
2. Gaseous fuel supplied to gas turbines must meet PWPS fuel specification FR-2, liquid fuel must meet FR-1.
3. Water used for burner injection must meet PWPS specification AR-1 (demin water).
4. Primary NOx control by water injection.
5. Data shown for GT water injection to 25 ppmvd @15% O2 for gas fuel and 42 ppmvd @15% O2 for liquid fuel.
6. All data supplied based on altitude of Sea Level Alt. (14.696 psia).
7. Engine performance with chiller in-service is based on a compressor inlet temperature of 10C.
8. Supply of chiller coils to the inlet is by PWPS, with chiller system provided by others.
9. Performance to be corrected for changes in ambient temperature, ambient pressure, and relative humidity from the guarantee reference conditions, whether the chiller is in-service or not.
10. In the event that the combination of ambient conditions and chiller performance can not meet 10C inlet temperature, then a root-cause investigation shall be funded by the Customer, with the supplier responsible for the shortfall being financially responsible for the miss.
11. Inlet loss estimated at 3.2 in W.C. with inlet Evaporative Cooler, and 3.5 in W.C. with Chiller.
    No correction of test results for inlet loss.
12. Exhaust loss for all cases estimated at 6 in W.C. for CO conv. System and 60 ft Braden exhaust stack.
    All emission concentrations corrected to 15% O2.
13. Secondary cooling air is separately exhausted from the Primary GT exhaust flow for the option with CO converter.

13A. Exhaust exit velocity is based on 70.882 ft2 exit discharge area of the 60 ft Braden stack.

14. Data designated as "primary exhaust" is referenced to the GT exhaust and does not include secondary cooling air.
15. All data submitted is based upon 72-290 generator operating at 60Hz and 0.85 power factor @13.8 kV.
16. Net Power = Power measured at the generator terminals, minus power island auxiliary and EVAP loads.

16A. BOP loads, GSU losses, Chiller and gas compression loads are not included in Net Power output or Net Heat Rate determinations.

17. Guaranteed values indicated by the following designations, all other data are estimates: (G) or **value**
18. Performance Acceptance Test for GT Net Power Output and GT Net Heat Rates to be conducted per PWPS test procedures, instrumentation, and calculations; all being in accordance with ASME PTC-22 and PTC-19.1, which shall meet or exceed the requirements of ISO 2314, ISO 5167, and ISO 6976.
19. Performance acceptance testing for GT Net Power Output and GT Net Heat Rate shall be furnished by PWPS through independent third party contractor.
20. Performance and emissions are based upon assumed fuel compositions shown on sheet - 2.
21. SO2 data is estimated from Sulfur contents stated on sheet - 2, which PWPS does not control and therefore can't guarantee.
22. Emission data is representative of steady-state operation, and may not be indicative of transient operation.
23. Demonstration of (G) emission concentrations for NOx, CO, and VOC's are based on 1-hour averages, after operation under steady-state conditions for 2-hours.
24. Volatile Organic Compounds (VOC) are defined as non methane, non ethane, > 85% of the composition being ethene. Values shown are based upon PWPS experience and measurement using EPA Method 25.3.
25. Testing for PM10 shall conform to PWPS Quality Assurance documentation in addition to EPA Methods 25, 201, 202.
26. PM10 testing to (G) levels shall require 4 test runs of 4-hour duration per fuel, with the high run rejected.
    Volumetric flow rate for determination of PM10 to be per EPA Method 19, which utilized fuel flow, O2%, and F-factors.
27. PM10 testing to Method 202 shall utilize best-practices shown at http://www.epa.gov/ttn/emc/methods/method202.html for the reduction in positive biases relating "to the oxidation of soluble gases inadvertently captured in the cold impinger solutions used in Method 202 sampling trains", including but not limited to sampling trains "without the use of water-filled impingers", and/or correction of results to reduce positive bias error. In the event of high test results, retest data shall have PM10 contributions from the gas turbine inlets.
28. In consideration of high bias issues with PM10 measurements by R/M 202, PWPS may test with R/M 20X for both filt & cond PM10.
29. Emission guarantees are valid when tested by Emissions Contractor specified by PWPS.
30. Installation, commissioning, and operation of CO catalysts must be in accordance with manufacturers specification.

FT8-3 Swift Pac (with CO Converter)
Assumed Fuel Properties
Tampa-Electric

The following fuel properties are assumed as representative of site fuels, based on specified data.

Specified Natural Gas

	Volume - Mol %		Units	
		Hydrogen to Carbon Ratio	$H_{(mw)}$ / $C_{(mw)}$	0.328
Methane	95.08	Hydrocarbon Molecular Weight		16.712
Ethane	2.53	Gas Molar Weight		17.042
Propane	0.43	Higher Heating Value	Btu/lb	22,933
N-Butane	0.12		kJ/kg	53,342
Isobutane	0.09		Btu/SCF	1,034
N-Pentane	0.03		kJ/Nm3	3,848
Isopentane	0.04	Lower Heating Value	Btu/lb	20,671
N-Hexane	0.08		kJ/kg	48,081
Nitrogen	0.88		Btu/SCF	931.6
CO2 & He	0.72		kJ/Nm3	3,469
Total	100.0	Ratio HHV/LHV		1.109
		Specific Gravity		0.5884
		Assumed Max Sulfur	grains/100 scf	0.50
			mg/Nm3	12
			Weight %	0.002

Specified Liquid Fuel (ULSD)

	Assumed Wt %		Units	
Carbon	87.16	Hydrogen to Carbon Ratio		0.1470
Hydrogen	12.81	Higher Heating Value	Btu/lb	19553
Nitrogen	0.015		kJ/kg	45480
Oxygen	0.010	Lower Heating Value	Btu/lb	18360
Sulfur Max	0.0015		kJ/kg	42705
Total	100.0	Ratio HHV/LHV		1.065
		Specific Gravity		0.816

FT8-3 Swift Pac (with CO Converter)
Estimated Performance and Emissions, 100% Base-Load Data
Tampa-Electric

Configuration: Standard NE US Gas Fuel, WI to 25 ppmvd NOx @ 15% O2,
Sea Level Alt., 55% Ambient RH, 72-290 Generator at 60 Hz, 13.8 kV, 0.85 pf Simple-Cycle

														Sim Chiller
Performance Data														
Fuel Type		Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Percent of Swift Pac Unit Rating	%	100	100	100	100	100	100	100	100	100	100	100	100	100
Ambient Temperature	Deg F	10	30	49	70	92	110	60	70	80	92	100	110	92
Evaporative Cooler In-Service	Yes / No	No	No	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes	No
Chiller in Service	Yes / No	No	No	No	No	No	No	No	No	No	No	No	No	Yes
Compressor Inlet Temperature	Deg F	10	30	49	70	92	110	53	61	70	80	87	96	50
Ambient Pressure	Psia	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70
Relative Humidity	%	55	55	55	55	55	55	55	55	55	55	55	55	100
Inlet Loss	Inch H20	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.5
Exhaust Loss	Inch H20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Fuel Supply Temperature	Deg F	59	59	59	59	59	59	59	59	59	59	59	59	59
Fuel LHV	Btu/lb	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671
Fuel HHV	Btu/lb	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932
Ratio of HHV to LHV		1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109
Gross Power Output	MWe	62.423	62.501	62.466	58.939	54.220	49.924	62.017	60.649	59.176	57.228	55.859	54.263	62.367
Gross Heat Rate, HHV	Btu/kWhr	10,074	10,176	10,285	10,408	10,638	10,925	10,311	10,359	10,423	10,514	10,591	10,692	10,304
Power Island and Evap Aux Loads	kW	252	252	252	252	252	252	260	260	260	260	260	260	252
Net Power Output	MWe	62.171	62.249	62.214	58.687	53.968	49.672	61.757	60.389	58.916	56.968	55.599	54.003	62.115
Net Heat Rate, HHV	Btu/kWhr	10,115	10,218	10,327	10,452	10,858	10,980	10,354	10,404	10,469	10,731	10,640	10,743	10,346
Fuel Flow, per GT	lbs/hr	13,711	13,868	14,008	13,374	12,575	11,892	13,942	13,698	13,448	13,118	12,899	12,650	14,011
Burner Water Injection Flow, per GT	gal/min	28.7	30.1	31.3	30.1	28.4	27.0	31.2	30.7	30.3	29.6	29.1	28.6	31.4
EVAP Water Flow Rate, per GT	gal/min	0.0	0.0	0.0	0.0	0.0	0.0	2.4	2.8	3.1	3.5	3.8	4.0	0.0
Gaseous Fuel Flow @ 15C, per GT	SCF/hr	304,228	307,705	310,816	296,760	279,029	263,861	309,351	303,939	298,389	291,079	286,203	280,680	310,891
Emissions at GT Exit*														
NOx	ppmvd	25	25	25	25	25	25	25	25	25	25	25	25	25
NOx, as NO2, per GT	lbs/hr	31.4	31.7	32.1	30.6	28.8	27.2	31.9	31.4	30.8	30.0	29.5	29.0	32.1
VOC as C1	ppmvd	6.8	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
VOC as C1, per GT	lbs/hr	3.0	2.6	2.7	2.6	2.4	2.3	2.7	2.6	2.6	2.5	2.5	2.4	2.7
SO2	ppmvd	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
SO2, per GT	lbs/hr	0.48	0.48	0.49	0.47	0.44	0.41	0.49	0.48	0.47	0.46	0.45	0.44	0.49
TSP/PM10, Filterable and Cond, per GT	lbs/hr	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Exhaust Gas Flow, per GT **	lbs/sec	214	210	205	196	185	174	203	200	196	191	187	183	204
Exhaust Gas Temperature **	Deg F	806	849	890	908	930	954	893	901	909	919	927	937	892
Exhaust Gas Molecular Weight, Wet		28.26	28.21	28.14	28.07	27.92	27.72	28.08	28.03	27.97	27.88	27.79	27.67	28.08
Exhaust Gas Vol Flow Rate, per GT **	ACFS	7,012	7,098	7,176	6,978	6,706	6,459	7,158	7,084	7,005	6,897	6,824	6,741	7,178
Stack Exhaust Velocity, per GT **	ft/s	98.9	100.1	101.2	98.4	94.6	91.1	101.0	99.9	98.8	97.3	96.3	95.1	101.3
H2O	% Vol wet	8.98	9.55	10.25	10.89	12.18	14.04	10.81	11.21	11.76	12.62	13.37	14.55	10.80
O2	% Vol wet	13.7	13.4	13.1	12.9	12.7	12.3	12.9	12.9	12.8	12.6	12.4	12.2	12.9
CO2	% Vol wet	3.09	3.19	3.28	3.27	3.25	3.24	3.29	3.28	3.28	3.27	3.27	3.27	3.29
A	% Vol wet	0.873	0.869	0.863	0.857	0.845	0.827	0.858	0.854	0.849	0.841	0.834	0.823	0.858
N2	% Vol wet	73.4	73.0	72.5	72.0	71.0	69.5	72.1	71.8	71.4	70.7	70.1	69.2	72.1
Treated Exhaust Characteristics (Post CO Converter)*														
CO	ppmvd	8.7	8.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
CO, perGT	lbs/hr	6.6	6.2	4.7	4.5	4.2	4.0	4.7	4.6	4.5	4.4	4.3	4.2	4.7
Estimated Chiller Load Calculations														
Air Enthalpy into Chiller	Btu/lb													41.80
Air Enthalpy out off Chiller	Btu/lb													20.30
Delta Enthalpy through Chiller	Btu/lb													21.50
Airflow through Chiller, per GT	pps													197.06
Air Enthalpy removed by Chiller	Btu/s													4,237
Tons of Refrigeration, per GT	ton													1,271
Chiller load, per GT	kW													1,042
Chiller load, per SP	kW													2,084

Notes:
- * All ppmvd corrected to 15% O2
- ** Secondary Cooling Air Separately Exhausted

Guaranteed values are indicated by (G), or value
All other data are estimates.

FT8-3 Swift Pac (with CO Converter)
Estimated Performance and Emissions, Part-Load Data
Tampa-Electric

Configuration: Standard NE US Gas Fuel, WI to 25 ppmvd NOx @ 15% O2,
Sea Level Alt., 55% Ambient RH, 72-290 Generator at 60 Hz, 13.8 kV, 0.85 pf Simple-Cycle

Performance Data																
Fuel Type		Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Percent of Swift Pac Unit Rating	%	100	83	75	67	50	100	83	75	67	50	100	83	75	67	50
Ambient Temperature	Deg F	20	20	20	20	20	59	59	59	59	59	90	90	90	90	90
Evaporative Cooler In-Service	Yes / No	No	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Chiller in Service	Yes / No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Compressor Inlet Temperature	Deg F	20	20	20	20	20	52	52	52	52	52	79	79	79	79	79
Ambient Pressure	Psia	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70
Relative Humidity	%	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Inlet Loss	Inch H20	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Exhaust Loss	Inch H20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Fuel Supply Temperature	Deg F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
Fuel LHV	Btu/lb	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671	20,671
Fuel HHV	Btu/lb	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932	22,932
Ratio of HHV to LHV		1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109
Gross Power Output	MWe	62.501	51.876	46.876	41.876	31.251	62.155	51.589	46.617	41.644	31.078	57.586	47.797	43.190	38.583	28.793
Gross Heat Rate, HHV	Btu/kWhr	10,125	10,255	10,442	10,700	11,517	10,306	10,459	10,652	10,909	11,738	10,495	10,793	11,013	11,287	12,181
Power Island and Evap Aux Loads	kW	252	252	252	252	252	260	260	260	260	260	260	260	260	260	260
Net Power Output	MWe	62.249	51.624	46.624	41.624	30.999	61.895	51.329	46.357	41.384	30.818	57.326	47.537	42.930	38.323	28.533
Net Heat Rate, HHV	Btu/kWhr	10,166	10,305	10,499	10,765	11,611	10,349	10,512	10,712	10,977	11,837	10,543	10,852	11,080	11,364	12,292
Fuel Flow, per GT	lbs/hr	13,797	11,599	10,673	9,770	7,847	13,967	11,764	10,827	9,905	7,954	13,177	11,248	10,371	9,495	7,647
Burner Water Injection Flow, per GT	gal/min	29.4	22.8	20.4	18.1	13.3	31.3	24.5	21.9	19.4	14.5	29.7	24.0	21.5	19.2	14.4
EVAP Water Flow Rate, per GT	gal/min	0.0	0.0	0.0	0.0	0.0	2.3	2.2	2.1	2.0	1.8	3.4	3.2	3.1	2.9	2.6
Gaseous Fuel Flow @ 15C, per GT	SCF/hr	306,139	257,365	236,811	216,777	174,125	309,905	261,032	240,229	219,772	176,484	292,386	249,577	230,119	210,687	169,676
Emissions at GT Exit*																
NOx	ppmvd	25	25	25	25	25.5	25	25	25	25	25	25	25	25	25	25
NOx, as NO2, per GT	lbs/hr	31.6	26.5	24.4	22.3	18.2	32.0	26.9	24.8	22.6	18.2	30.2	25.7	23.7	21.7	17.5
VOC as C1	ppmvd	6.0	13.9	15.6	16.7	40.4	6.0	7.4	11.0	14.0	17.2	6.0	6.0	7.6	11.2	16.0
VOC as C1, per GT	lbs/hr	2.6	5.1	5.3	5.2	10.1	2.7	2.8	3.8	4.4	4.3	2.5	2.1	2.5	3.4	3.9
SO2	ppmvd	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
SO2, per GT	lbs/hr	0.48	0.40	0.37	0.34	0.27	0.49	0.41	0.38	0.35	0.28	0.46	0.39	0.36	0.33	0.27
TSP/PM10, Filterable and Cond, per GT	lbs/hr	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Exhaust Gas Flow, per GT **	lbs/sec	212	198	190	181	161	204	190	182	173	153	192	177	169	161	143
Exhaust Gas Temperature **	Deg F	828	765	748	733	701	893	834	817	802	767	917	879	864	848	814
Exhaust Gas Molecular Weight, Wet		28.23	28.33	28.36	28.39	28.46	28.08	28.17	28.21	28.24	28.31	27.89	27.97	28.00	28.03	28.10
Exhaust Gas Vol Flow Rate, per GT **	ACFS	7,058	6,263	5,910	5,558	4,783	7,166	6,360	6,000	5,638	4,847	6,917	6,186	5,843	5,495	4,734
Stack Exhaust Velocity, per GT **	ft/s	99.6	88.4	83.4	78.4	67.5	101.1	89.7	84.6	79.5	68.4	97.6	87.3	82.4	77.5	66.8
H2O	% Vol wet	9.25	8.14	7.76	7.41	6.57	10.77	9.68	9.29	8.90	8.05	12.45	11.62	11.24	10.86	10.00
O2	% Vol wet	13.5	14.3	14.6	14.8	15.4	12.9	13.7	14.0	14.2	14.9	12.6	13.2	13.5	13.7	14.4
CO2	% Vol wet	3.14	2.83	2.72	2.62	2.38	3.29	2.99	2.88	2.77	2.52	3.27	3.04	2.93	2.82	2.57
A	% Vol wet	0.871	0.879	0.881	0.884	0.889	0.858	0.866	0.868	0.871	0.877	0.842	0.848	0.851	0.853	0.859
N2	% Vol wet	73.2	73.8	74.1	74.3	74.7	72.1	72.8	73.0	73.2	73.7	70.8	71.3	71.5	71.7	72.2
Treated Exhaust Characteristics (Post CO Converter)*																
CO	ppmvd	8.0	13.3	14.1	14.6	20.9	6.0	9.2	11.6	13.3	14.8	6.0	8.0	9.3	11.7	14.3
CO, per GT	lbs/hr	6.2	8.6	8.4	7.9	9.1	4.7	6.0	7.0	7.3	6.6	4.4	5.0	5.4	6.2	6.1

Estimated Chiller Load Calculations

Air Enthalpy into Chiller	Btu/lb
Air Enthalpy out off Chiller	Btu/lb
Delta Enthalpy through Chiller	Btu/lb
Airflow through Chiller, per GT	pps
Air Enthalpy removed by Chiller	Btu/s
Tons of Refrigeration, per GT	ton
Chiller load, per GT	kW
Chiller load, per SP	kW

Notes:
* All ppmvd corrected to 15% O2
** Secondary Cooling Air Separately Exhausted

Guaranteed values are indicated by (G), or $\boxed{\text{value}}$
All other data are estimates.

FT8-3 Swift Pac (with CO Converter)
Estimated Performance and Emissions, 100% Base-Load Data
Tampa-Electric

**Configuration: Specified Liquid Fuel (ULSD), WI to 42 ppmvd NOx @ 15% O2,
Sea Level Alt., 55% Ambient RH, 72-290 Generator at 60 Hz, 13.8 kV, 0.85 pf Simple-Cycle**

														Sim Chiller
Performance Data														
Fuel Type		Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
Percent of Swift Pac Unit Rating	%	100	100	100	100	100	100	100	100	100	100	100	100	100
Ambient Temperature	Deg F	10	30	50	75	92	110	60	75	89	92	100	110	92
Evaporative Cooler In-Service	Yes / No	No	No	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes	No
Chiller in Service	Yes / No	No	No	No	No	No	No	No	No	No	No	No	No	Yes
Compressor Inlet Temperature	Deg F	10	30	50	75	92	110	53	66	78	80	87	96	50
Ambient Pressure	Psia	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70
Relative Humidity	%	55	55	55	55	55	55	55	55	55	55	55	55	100
Inlet Loss	Inch H20	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.5
Exhaust Loss	Inch H20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Fuel Supply Temperature	Deg F	127	127	127	127	127	127	127	127	127	127	127	127	127
Fuel LHV	Btu/lb	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360
Fuel HHV	Btu/lb	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553
Ratio of HHV to LHV		1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065
Gross Power Output	MWe	56.048	56.126	56.182	56.287	52.189	48.013	56.202	56.267	56.203	55.668	54.238	51.990	56.090
Gross Heat Rate, HHV	Btu/kWhr	9,822	9,936	10,057	10,217	10,446	10,740	10,080	10,166	10,253	10,282	10,365	10,519	10,070
Power Island and Evap Aux Loads	kW	277	277	277	277	277	277	285	285	285	285	285	285	277
Net Power Output	MWe	55.771	55.849	55.905	56.010	51.912	47.736	55.917	55.982	55.918	55.383	53.953	51.705	55.813
Net Heat Rate, HHV	Btu/kWhr	9,871	9,985	10,107	10,268	10,670	10,802	10,131	10,218	10,305	10,500	10,420	10,577	10,120
Fuel Flow, per GT	lbs/hr	14,076	14,259	14,448	14,705	13,940	13,185	14,486	14,626	14,735	14,636	14,375	13,984	14,443
Burner Water Injection Flow, per GT	gal/min	28.7	30.4	32.1	34.3	32.6	31.0	32.3	33.5	34.4	34.2	33.7	32.8	32.1
EVAP Water Flow Rate, per GT	gal/min	0.0	0.0	0.0	0.0	0.0	0.0	2.3	2.9	3.4	3.5	3.7	3.9	0.0
Gaseous Fuel Flow @ 15C, per GT	SCF/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emissions at GT Exit*														
NOx	ppmvd	42	42	42	42	42	42	42	42	42	42	42	42	42
NOx, as NO2, per GT	lbs/hr	49.1	49.7	50.4	51.3	48.6	46.0	50.5	51.0	51.4	51.1	50.2	48.8	50.4
VOC as C1	ppmvd	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
VOC as C1, per GT	lbs/hr	2.0	2.1	2.1	2.1	2.0	1.9	2.1	2.1	2.1	2.1	2.1	2.0	2.1
SO2	ppmvd	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
SO2, per GT	lbs/hr	0.46	0.47	0.48	0.49	0.46	0.44	0.48	0.48	0.49	0.48	0.47	0.46	0.48
TSP/PM10, Filterable and Cond, per GT	lbs/hr	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Exhaust Gas Flow, per GT **	lbs/sec	208	203	198	192	182	171	197	194	191	190	186	180	197
Exhaust Gas Temperature **	Deg F	771	815	860	915	936	959	866	894	920	923	931	943	860
Exhaust Gas Molecular Weight, Wet		28.66	28.61	28.55	28.42	28.30	28.09	28.49	28.40	28.28	28.25	28.17	28.04	28.49
Exhaust Gas Vol Flow Rate, per GT **	ACFS	6,520	6,599	6,679	6,785	6,548	6,307	6,694	6,752	6,799	6,769	6,691	6,567	6,678
Stack Exhaust Velocity, per GT **	ft/s	92.0	93.1	94.2	95.7	92.4	89.0	94.4	95.3	95.9	95.5	94.4	92.6	94.2
H2O	% Vol wet	6.59	7.15	7.89	9.27	10.37	12.25	8.47	9.40	10.55	10.79	11.55	12.74	8.40
O2	% Vol wet	14.3	14.0	13.6	13.1	12.9	12.5	13.5	13.2	12.8	12.8	12.6	12.4	13.5
CO2	% Vol wet	3.93	4.08	4.22	4.41	4.39	4.39	4.24	4.34	4.42	4.42	4.42	4.42	4.22
A	% Vol wet	0.884	0.879	0.873	0.861	0.851	0.833	0.868	0.860	0.849	0.847	0.840	0.829	0.868
N2	% Vol wet	74.3	73.9	73.4	72.3	71.5	70.0	72.9	72.2	71.4	71.2	70.6	69.6	73.0
Treated Exhaust Characteristics (Post CO Converter)*														
CO	ppmvd	2.3	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
CO, per GT	lbs/hr	1.6	1.4	1.5	1.5	1.4	1.3	1.5	1.5	1.5	1.5	1.5	1.4	1.5
Estimated Chiller Load Calculations														
Air Enthalpy into Chiller	Btu/lb													41.80
Air Enthalpy out off Chiller	Btu/lb													20.30
Delta Enthalpy through Chiller	Btu/lb													21.50
Airflow through Chiller, per GT	pps													189.99
Air Enthalpy removed by Chiller	Btu/s													4,085
Tons of Refrigeration, per GT	ton													1,225
Chiller load, per GT	kW													1,005
Chiller load, per SP	kW													2,010

Notes:
- * All ppmvd corrected to 15% O2
- ** Secondary Cooling Air Separately Exhausted

Guaranteed values are indicated by (G), or $\boxed{\text{value}}$
All other data are estimates.

FT8-3 Swift Pac (with CO Converter)
Estimated Performance and Emissions, Part-Load Data
Tampa-Electric

Configuration: Specified Liquid Fuel (ULSD), WI to 42 ppmvd NOx @ 15% O2,
Sea Level Alt., 55% Ambient RH, 72-290 Generator at 60 Hz, 13.8 kV, 0.85 pf Simple-Cycle

Performance Data																
Fuel Type		Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
Percent of Swift Pac Unit Rating	%	100	83	75	67	50	100	83	75	67	50	100	83	75	67	50
Ambient Temperature	Deg F	20	20	20	20	20	59	59	59	59	59	90	90	90	90	90
Evaporative Cooler In-Service	Yes / No	No	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Chiller in Service	Yes / No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Compressor Inlet Temperature	Deg F	20	20	20	20	20	52	52	52	52	52	79	79	79	79	79
Ambient Pressure	Psia	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70
Relative Humidity	%	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Inlet Loss	Inch H20	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Exhaust Loss	Inch H20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Fuel Supply Temperature	Deg F	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
Fuel LHV	Btu/lb	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360	18,360
Fuel HHV	Btu/lb	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553	19,553
Ratio of HHV to LHV		1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065	1.065
Gross Power Output	MWe	56.065	46.534	42.049	37.564	28.033	56.167	46.619	42.125	37.632	28.084	56.020	46.497	42.015	37.533	28.010
Gross Heat Rate, HHV	Btu/kWhr	9,877	10,175	10,396	10,674	11,533	10,075	10,376	10,592	10,868	11,739	10,263	10,580	10,797	11,066	11,950
Power Island and Evap Aux Loads	kW	277	277	277	277	277	285	285	285	285	285	285	285	285	285	285
Net Power Output	MWe	55.788	46.257	41.772	37.287	27.756	55.882	46.334	41.840	37.347	27.799	55.735	46.212	41.730	37.248	27.725
Net Heat Rate, HHV	Btu/kWhr	9,926	10,236	10,465	10,753	11,648	10,126	10,440	10,665	10,951	11,860	10,315	10,645	10,870	11,151	12,073
Fuel Flow, per GT	lbs/hr	14,159	12,106	11,178	10,252	8,267	14,470	12,368	11,409	10,457	8,430	14,701	12,579	11,599	10,620	8,559
Burner Water Injection Flow, per GT	gal/min	29.6	23.6	21.1	18.6	13.7	32.2	25.9	23.1	20.5	15.1	34.3	27.7	24.8	22.0	16.3
EVAP Water Flow Rate, per GT	gal/min	0.0	0.0	0.0	0.0	0.0	2.3	2.1	2.0	1.9	1.7	3.4	3.1	3.0	2.9	2.6
Gaseous Fuel Flow @ 15C, per GT	SCF/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emissions at GT Exit*																
NOx	ppmvd	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
NOx, as NO2, per GT	lbs/hr	49.4	42.2	38.9	35.7	28.7	50.5	43.1	39.8	36.4	29.3	51.3	43.9	40.4	37.0	29.8
VOC as C1	ppmvd	5.0	6.5	8.7	12.0	25.4	5.0	5.0	5.0	6.0	13.1	5.0	5.0	5.0	5.0	7.8
VOC as C1, per GT	lbs/hr	2.0	2.3	2.8	3.5	6.0	2.1	1.8	1.6	1.8	3.2	2.1	1.8	1.7	1.5	1.9
SO2	ppmvd	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
SO2, per GT	lbs/hr	0.47	0.40	0.37	0.34	0.27	0.48	0.41	0.38	0.35	0.28	0.49	0.42	0.38	0.35	0.28
TSP/PM10, Filterable and Cond, per GT	lbs/hr	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Exhaust Gas Flow, per GT **	lbs/sec	205	190	182	173	154	197	182	174	166	147	190	175	168	160	142
Exhaust Gas Temperature **	Deg F	793	758	744	731	699	864	828	814	799	767	921	887	872	856	823
Exhaust Gas Molecular Weight, Wet		28.64	28.68	28.70	28.72	28.76	28.49	28.54	28.56	28.58	28.63	28.27	28.32	28.34	28.36	28.41
Exhaust Gas Vol Flow Rate, per GT **	ACFS	6,558	5,883	5,567	5,247	4,534	6,688	5,996	5,669	5,339	4,610	6,788	6,085	5,750	5,411	4,669
Stack Exhaust Velocity, per GT **	ft/s	92.5	83.0	78.5	74.0	64.0	94.4	84.6	80.0	75.3	65.0	95.8	85.8	81.1	76.3	65.9
H2O	% Vol wet	6.85	6.16	5.86	5.56	4.88	8.41	7.69	7.37	7.04	6.31	10.63	9.90	9.57	9.22	8.45
O2	% Vol wet	14.2	14.7	14.9	15.2	15.7	13.5	14.1	14.3	14.6	15.2	12.8	13.4	13.6	13.9	14.5
CO2	% Vol wet	4.00	3.71	3.58	3.45	3.13	4.23	3.93	3.79	3.65	3.32	4.42	4.12	3.97	3.82	3.48
A	% Vol wet	0.882	0.887	0.889	0.892	0.897	0.868	0.874	0.876	0.879	0.884	0.849	0.854	0.857	0.859	0.865
N2	% Vol wet	74.1	74.5	74.7	74.9	75.3	73.0	73.4	73.6	73.8	74.3	71.3	71.8	72.0	72.2	72.7
Treated Exhaust Characteristics (Post CO Converter)*																
CO	ppmvd	2.1	2.8	3.2	3.7	5.1	2.0	2.0	2.3	2.7	3.8	2.0	2.0	2.0	2.1	3.8
CO, per GT	lbs/hr	1.5	1.7	1.8	1.9	2.1	1.5	1.3	1.4	1.4	1.6	1.5	1.3	1.2	1.1	0.6
Estimated Chiller Load Calculations																
Air Enthalpy into Chiller	Btu/lb															
Air Enthalpy out off Chiller	Btu/lb															
Delta Enthalpy through Chiller	Btu/lb															
Airflow through Chiller, per GT	pps															
Air Enthalpy removed by Chiller	Btu/s															
Tons of Refrigeration, per GT	ton															
Chiller load, per GT	kW															
Chiller load, per SP	kW															

Notes:
- * All ppmvd corrected to 15% O2
- ** Secondary Cooling Air Separately Exhausted

Guaranteed values are indicated by (G), or value
All other data are estimates.

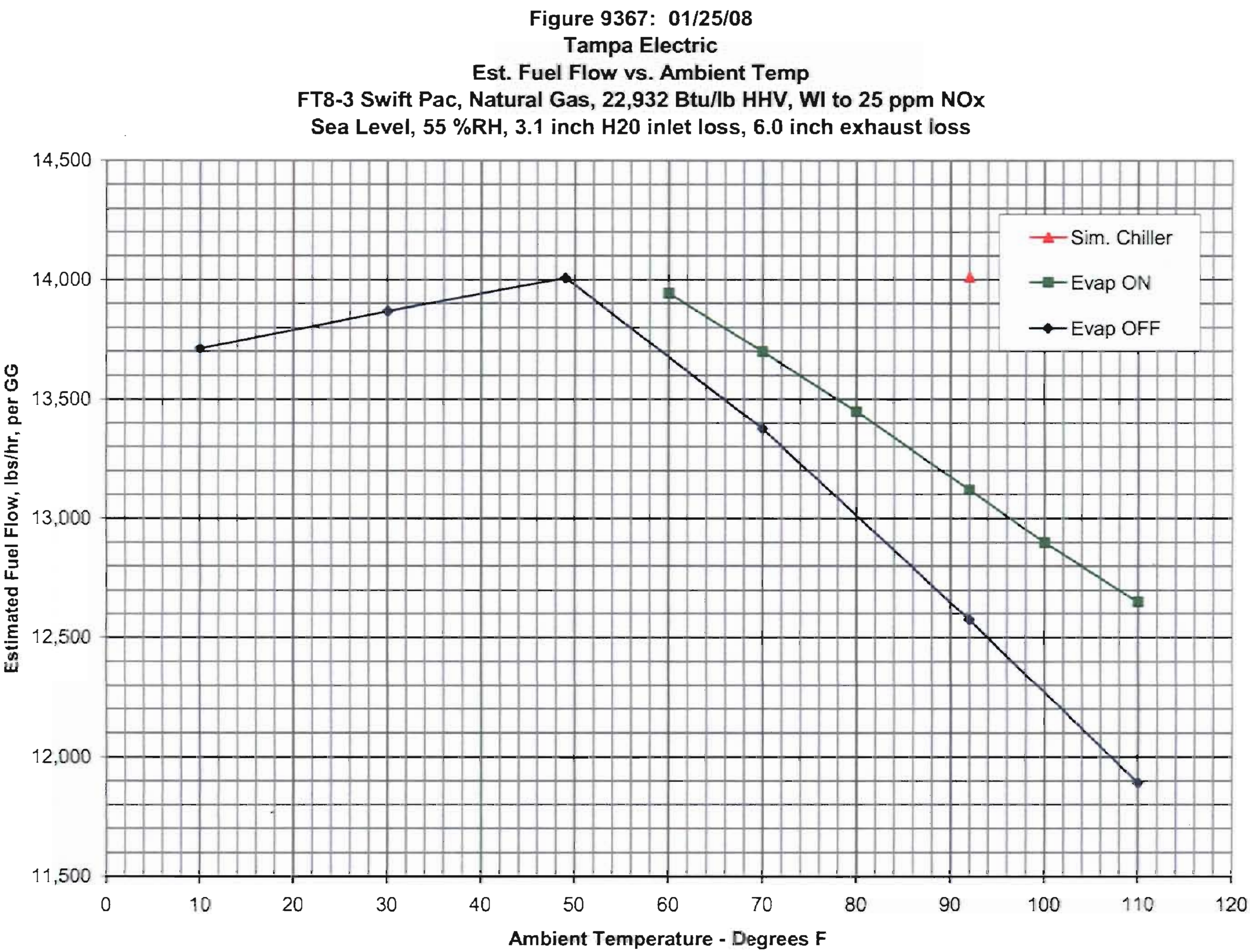

Figure 9367: 01/25/08
Tampa Electric
Est. Fuel Flow vs. Ambient Temp
FT8-3 Swift Pac, Natural Gas, 22,932 Btu/lb HHV, WI to 25 ppm NOx
Sea Level, 55 %RH, 3.1 inch H20 inlet loss, 6.0 inch exhaust loss
Sim. Chiller
Evap ON
Evap OFF
Estimated Fuel Flow, lbs/hr, per GG
14,500
14,000
13,500
13,000
12,500
12,000
11,500
0
10
20
30
40
50
60
70
80
90
100
110
120
Ambient Temperature - Degrees F

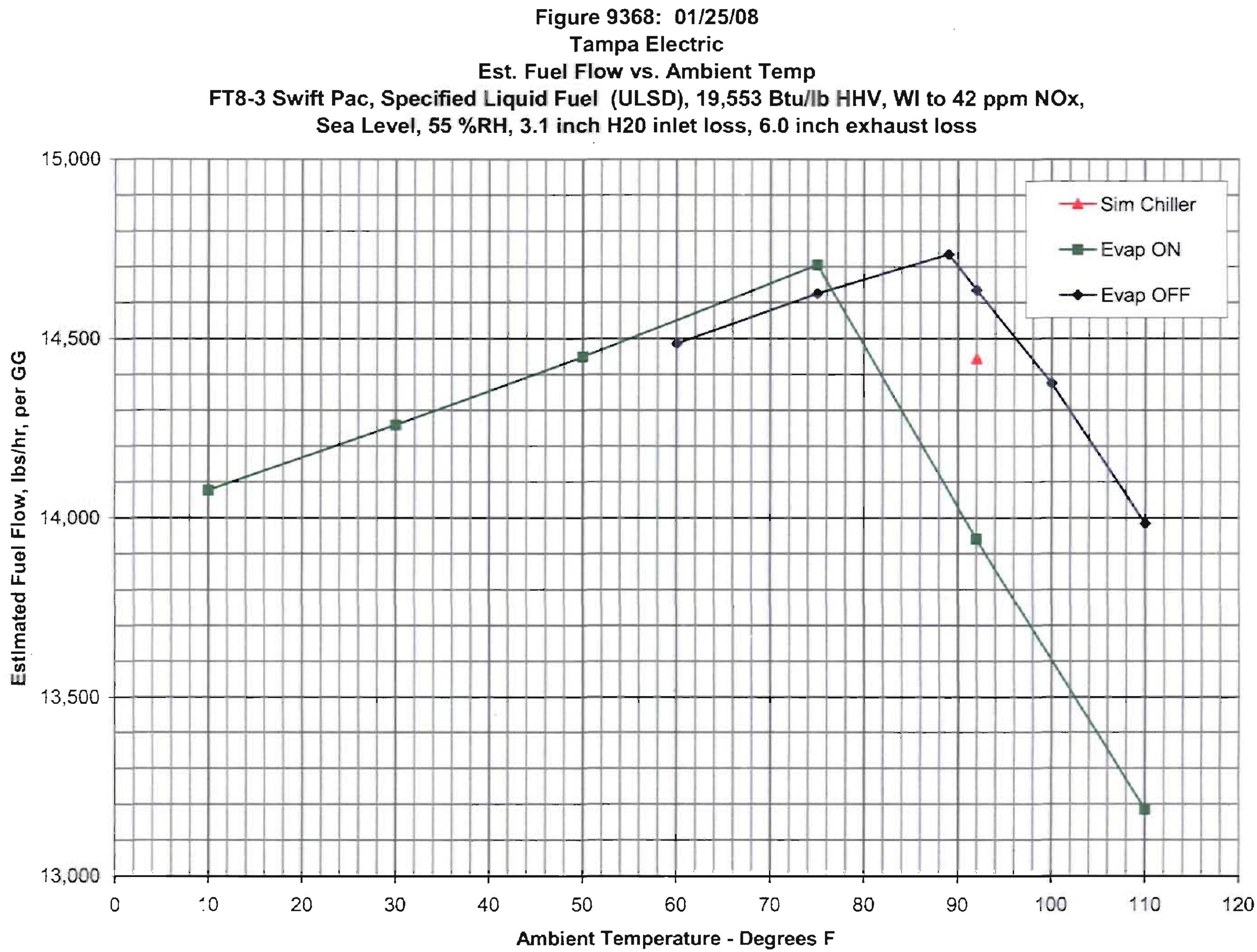

Figure 9368: 01/25/08
Tampa Electric
Est. Fuel Flow vs. Ambient Temp
FT8-3 Swift Pac, Specified Liquid Fuel (ULSD), 19,553 Btu/lb HHV, WI to 42 ppm NOx,
Sea Level, 55 %RH, 3.1 inch H20 inlet loss, 6.0 inch exhaust loss
Sim Chiller
Evap ON
Evap OFF
15,000
14,500
14,000
13,500
13,000
0
10
20
30
40
50
60
70
80
90
100
110
120
Estimated Fuel Flow, lbs/hr, per GG
Ambient Temperature - Degrees F

ECT
Environmental Consulting & Technology, Inc.

September 29, 2008

SENT BY E-MAIL ON 09/29/08

RECEIVED
SEP 30 2008
BUREAU OF AIR REGULATION

Mr. Syed Arif, P.E.
Florida Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Re: Tampa Electric Company – Big Bend Station
Simple-Cycle Combustion Turbine Unit 4
Project No. 0570039-040-AC

Subject: Response to Request for Additional Information – September 19, 2008
Professional Engineer Certification

Dear Mr. Arif:

Tampa Electric Company (TEC) submitted an air construction permit application to the Department on August 21, 2008 requesting authorization to install and operate two simple cycle combustion turbines at its Big Bend Station. In response to this permit application, the Department requested additional information in correspondence to TEC dated September 19, 2008. On September 22, 2008, TEC submitted a response to the Department's RAI.

A Professional Engineer Certification with respect to the TEC RAI response is attached for your records.

If there are any questions, please contact me at (352) 248-3351 or e-mail at tdavis@ectinc.com.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis, P.E.
Principal Engineer

Attachment

cc: Mr. Bruce Mitchell, FDEP
Ms. Diana Lee, EPCHC
Mr. David Lukcic, TEC

3701 Northwest 98th Street
Gainesville, FL 32606
(352) 332-0444
FAX (352) 332-6722

TAMPA ELECTRIC COMPANY
BIG BEND STATION

SIMPLE-CYCLE COMBUSTION TURBINES UNIT 4
RESPONSE TO FDEP REQUEST FOR ADDITIONAL INFORMATION

Professional Engineer Certification

Professional Engineer Statement:

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

(1) To the best of my knowledge, the information presented in the response by Tampa Electric Company (TEC) to the Department's September 19, 2008 request for additional information regarding the Big Bend Station Simple-Cycle Combustion Turbines Unit 4 Project are true, accurate, and complete based on my review of material provided by TEC engineering and environmental staff; and

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

Signature ____________ *Date* 9/25/08

(seal)

* Certification is applicable to the Tampa Electric Company (TEC) response to the Department's September 19, 2008 request for additional information regarding the Simple-Cycle Combustion Turbines Unit 4 Project at its Big Bend Station.