STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

City of Tallahassee, Electric Utilities
Arvah B. Hopkins Generating Station
2602 Jackson Bluff Road
Tallahassee, Florida 32304

Air Permit No. 0730003-009-AC
Arvah B. Hopkins Generating Station
Unit 2 Re-Powering Project

Authorized Representative:
Mr. Robert E. McGarrah, Production Superintendent

Enclosed is Final Air Permit No. 0730003-009-AC, which authorizes the construction of a new General Electric 7FA combustion turbine (188 MW) and gas-fired heat recovery steam generator (HRSG) to re-power the existing Hopkins Unit 2 steam turbine-electrical generator set (238 MW). The existing Unit 2 boiler will be permanently shut down as part of this project. The new equipment will be installed at the Arvah B. Hopkins Generating Station, which is located in Leon County at 1125 Geddie Road, Tallahassee, Florida. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes 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 thirty (30) days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit package (including the Final Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 9/19/06 to the persons listed:

Mr. Robert E. McGarrah, City of Tallahassee*
Mr. John Powell, City of Tallahassee
Mr. Ken Kosky, Golder Associates Inc.
Ms. Sandra Veazey, NWD Office
Mr. Jim Little, EPA Region 4
Mr. Hamilton Oven, DEP Siting Office

Clerk Stamp

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

Barbara J. Friday (Clerk) 9/19/06 (Date)

PERMITTEE

City of Tallahassee, Electric Utilities
Arvah B. Hopkins Generating Station
2602 Jackson Bluff Road
Tallahassee, Florida 32304

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation, Air Permitting North Program
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400

PROJECT

Air Permit No. 0730003-009-AC
Arvah B. Hopkins Generating Station

This permit authorizes construction of a new General Electric 7FA combustion turbine (188 MW) and gas-fired heat recovery steam generator (HRSG) to re-power the existing Hopkins Unit 2 steam turbine-electrical generator set (238 MW). The existing Unit 2 boiler will be permanently shut down as part of this project. The new combined cycle unit includes an SCR system and avoids PSD preconstruction review. The new equipment will be installed at the Arvah B. Hopkins Generating Station, which is located in Leon County at 1125 Geddie Road, Tallahassee, Florida.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on August 28, 2006. The Public Notice was published in the Tallahassee Democrat on September 1, 2006. The Department received the proof of publication by email on September 6, 2006.

COMMENTS/PETITIONS

No comments were received on the draft permit package. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

CONCLUSION

Only minor revisions were made to correct typographical errors, etc. The final action of the Department is to issue the permit with the changes described above.

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

PERMITTEE

City of Tallahassee, Electric Utilities
Arvah B. Hopkins Generating Station
2602 Jackson Bluff Road
Tallahassee, Florida 32304

Authorized Representative:
Mr. Robert E. McGarrah, Production Superintendent

Air Permit No. 0730003-009-AC
Arvah B. Hopkins Generating Station
Facility ID No. 0730003
SIC No. 4911
Unit 2 Re-Powering Project
Permit Expires: July 1, 2009

PROJECT AND LOCATION

This permit authorizes the construction of a General Electric 7FA combustion turbine (188 MW) and gas-fired heat recovery steam generator (HRSG) to re-power the existing Unit 2 steam turbine-electrical generator set (238 MW). The existing Unit 2 boiler will be permanently shut down as part of this project. The new equipment will be installed at the Arvah B. Hopkins Generating Station, which is located in Leon County at 1125 Geddie Road, Tallahassee, Florida.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Parts 60 and 63 of the Code of Federal Regulations. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

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9/16/06

Joseph Kahn, P.E., Director
Division of Air Resource Management

(Date)

FACILITY AND PROJECT DESCRIPTION

The City of Tallahassee operates the Arvah B. Hopkins Generating Station, which is an existing power plant (SIC No. 4911). The plant currently consists of:

- Steam Generating Unit 1 (EU-001) is a Foster-Wheeler Corporation Model No. SF-5 boiler rated at 75 MW. The unit is authorized to fire natural gas or fuel oil. It is subject to the Phase II Acid Rain provisions. The unit began commercial operation in May of 1971.
- Combustion Turbine 1 (EU-002) is a Westinghouse Model No. W191G combustion turbine rated at 16.47 MW. The unit is authorized to fire natural gas or No. 2 oil. It is not subject to NSPS Subpart GG for combustion turbines. The unit began commercial operation in February of 1970.
- Combustion Turbine 2 (EU-003) is a Westinghouse Model No. W251G combustion turbine rated at 26.8 MW. The unit is authorized to fire natural gas or No. 2 oil. It is not subject to NSPS Subpart GG for combustion turbines. The unit began commercial operation in September of 1972.
- Steam Generating Unit 2 (EU-004) is a Babcock & Wilcox Model No. RB-533 boiler rated at 238 MW. The unit is authorized to fire natural gas or fuel oil. It is subject to the Phase II Acid Rain provisions and a Florida Power Plant Site Certification No. PA 74-03D. The unit began commercial operation in October of 1977.
- The facility also includes: fugitive VOC sources (EU-005) such as painting operations; general purpose engines (EU-006); and emergency generators (EU-007).
- LM 6000PC SPRINT simple cycle combustion turbines (EU-031 and EU-032). Each unit has a capacity of approximately 50 MW and fires both natural gas and distillate oil. NOx emissions are controlled by water injection and a hot selective catalytic reduction (SCR) system.

{Permitting Note: On May 10, 2004, the Department issued Permit No. 0730003-004-AC, which authorized the temporary installation of 23 portable combustion turbine-generator sets (EU-008 through EU-030) rated at approximately 5.5 MW (each) of output. The purpose of the project was to ensure reliable power during the temporary period that Combined Cycle Unit 8 at the City of Tallahassee's Purdom Plant was being repaired and returned to service. These units have been removed from the site and are no longer authorized to operate.}

This permit authorizes shutdown of the Unit 2 boiler and the re-powering of the Unit 2 steam turbine-electrical generator by installing the following equipment:

ID	Emission Unit Description
033	General Electric 7FA Combined Cycle Combustion Turbine to re-power Unit 2

Due to the shutdown of the Unit 2 boiler, the project avoids PSD preconstruction review for all pollutants.

REGULATORY CLASSIFICATION

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

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

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

PSD: The facility is a PSD-major facility in accordance with Rule 62-212.400, F.A.C.

NSPS: The facility will operate units subject to New Source Performance Standards in 40 CFR 60.

NEHSAP: The facility will operate units subject to National Emissions Standards for HAPs in 40 CFR 63.

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

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's Northwest District Office at 160 Governmental Center, Suite 308, Pensacola, Florida 32502-5794.

3. Appendices: The following Appendices are attached as part of this permit: Appendix A (Citation Format); Appendix B (General Conditions); and Appendix C (Common Conditions); Appendix D (NSPS Subpart KKKK Provisions - Combustion Turbines and Duct Burners); Appendix E (NESHAP Subpart YYYY Provisions – Combustion Turbines); and Appendix F (Emissions Summary).

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

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

6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

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

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

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

10. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(3), F.A.C.]

A. General Electric 7FA Combined Cycle Unit (EU-033)

This section of the permit addresses the following emissions unit.

Emissions Unit No. 033 - General Electric 7FA Combined Cycle Unit
The unit consists of a General Electric 7FA combustion turbine, automated combustion turbine control system, a heat recovery steam generator (HRSG), a gas-fired duct burner system, a HRSG stack, a bypass stack, and CO and NOx CEMS. The combustion turbine will produce a nominal 188 MW and the HRSG will be used to re-power the existing Unit 2 steam turbine-electrical generator to produce a nominal 238 MW. In the combustion turbine, natural gas will be fired as the primary fuel and distillate oil will be fired as a restricted alternative fuel from on site storage tanks. Based on the higher heating value of each fuel and a compressor inlet temperature of 25° F, the design maximum heat input rates are 1899 MMBtu per hour for gas firing and 2079 MMBtu per hour for oil firing. Natural gas will be the sole fuel for the duct burner system rated at a maximum heat input rate of 765 MMBtu per hour. Nitrogen oxide emissions will be controlled by a selective catalytic reduction (SCR) system plus the dry low-NOx (DLN) combustion system when firing natural gas and water injection when firing distillate oil. Emissions of carbon monoxide and volatile organic compounds will be minimized by the firing of clean fuels and the high combustion temperatures of the combustion turbine. Emissions of particulate matter will be minimized by the large inlet air filtration system and the efficient combustion of the proposed fuels. Emissions of sulfuric acid mist and sulfur dioxide will be minimized by the firing of natural gas as the primary fuel and the restricted firing of distillate oil ($\leq$ 0.05% sulfur by weight) as a backup fuel. When firing natural gas and duct firing, exhaust gas at 188° F will leave the HRSG and exit a stack that is 18 feet in diameter and 150 feet tall with a volumetric flow rate of approximately 1,016,100 acfm. When firing distillate oil and duct firing, exhaust gas at 204° F will leave the HRSG and exit a stack that is 18 feet in diameter and 150 feet tall with a volumetric flow rate of approximately 1,090,210 acfm. When operating in simple cycle mode with the blanking plate installed, exhaust gas at 1114° F will exit an emergency bypass stack that is also 18 feet in diameter and 150 feet tall with a volumetric flow rate of approximately 2,433,700 acfm. Temperatures and gas flows assume a compressor inlet temperature of 59° F.

EQUIPMENT

1. Unit 2 Boiler – Shutdown: Prior to commencing commercial operation of the new combined cycle combustion turbine, the permittee shall permanently shutdown and render incapable of operation the existing Unit 2 boiler. [Application No. 0730003-009-AC; Rule 62-212.400(12), F.A.C.]

2. New Combined Cycle Unit:

   a. *Combustion Turbine*: The permittee is authorized to install, tune, operate, and maintain the following equipment: a General Electric 7FA combustion turbine-electrical generator set (Model 7241 or equivalent); an inlet air filtration system; an automated combustion turbine control system (Mark VI or equivalent), a heat recovery steam generator (HRSG); a gas-fired duct burner system; a HRSG stack; a bypass stack; and CO and NOx CEMS. The combustion turbine will produce a nominal 188 MW when firing natural gas with a heat input rate of 1899 MMBtu per hour.

   b. *HRSG*: The permittee is authorized to install, operate, and maintain a new heat recovery steam generator (HRSG) designed to recover heat energy from the combustion turbine and deliver steam to the existing Unit 2 steam turbine-electrical generator set. The HRSG will be equipped with supplemental gas-fired duct burner system having a maximum heat input rate of 765 MMBtu per hour (HHV).

   [Application No. 0730003-009-AC; Design]

3. Fuel Tanks: The existing plant includes two 10,000 bbl diesel storage tanks, a 55,000 bbl No. 6 oil storage tank, and a 180,000 bbl No. 6 oil storage tank. As part of the project, the permittee is authorized to convert the 180,000 bbl No. 6 oil storage tank to store diesel (distillate oil). The converted tank and the two existing diesel tanks will supply the new combined cycle combustion turbine. [Application No. 0730003-009-AC]

AIR POLLUTION CONTROL SYSTEMS

4. DLN Combustion: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or

better) to control NO_X emissions from the combustion turbine when firing natural gas. Prior to the initial emissions performance tests required for the combustion turbine, the DLN combustors and automated combustion turbine control system shall be tuned without the SCR in operation to achieve the permitted CO and NOx levels for simple cycle HRSG/SCR bypass operation. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards. [Application No. 0730003-009-AC; Design]

5. Water Injection Technology: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions when firing distillate oil. Prior to the initial emissions performance tests, the water injection system shall be tuned without the SCR in operation to achieve a target NOx level of 42 ppmvd @ 15% oxygen, which represents the vendor's specification for oil firing. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards. [Application No. 0730003-009-AC; Design]

6. SCR System: The permittee shall install, operate, and maintain a selective catalytic reduction (SCR) system to control NOx emissions from the combustion turbine when firing either natural gas or distillate oil during combined cycle operation (including periods when steam is dumped to a condenser). The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions. The SCR system shall be designed to achieve an ammonia slip level of 5 ppmvd @ 15% oxygen. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}*

7. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. The SCR system is not required to be in operation when the unit is operating in simple cycle HRSG/SCR bypass mode. [Rule 62-210.650, F.A.C.]

PERFORMANCE RESTRICTIONS

8. Authorized Fuels: The combustion turbine shall fire only natural gas and distillate oil. The maximum sulfur content of distillate oil shall not exceed 0.05% by weight. The duct burner system shall fire only natural gas. [Application No. 0730003-009-AC; Rule 62-210.200(PTE), F.A.C.]

9. Permitted Capacities:

   a. *Combustion Turbine*: The design maximum heat input rates are 1899 MMBtu per hour for gas firing and 2079 MMBtu per hour for oil firing based on the higher heating value of each fuel, a compressor inlet temperature of 25° F, and full load operation. Heat input rates will vary depending upon combustion turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

   b. *Duct Burner*: The design maximum heat input rate to the duct burner system is 765 MMBtu per hour.

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

10. Restricted Operation:

    a. The hours of operation of the combustion turbine are not limited (8760 hours per year).

    b. Distillate oil firing in the combustion turbine shall not exceed 6,926,500 MMBtu during any consecutive 12 months (equivalent to 3500 hours of full load oil firing).

    c. The duct burner shall fire no more than 2,598,800 MMBtu of natural gas during any consecutive 12 months (equivalent to 3650 hours of full load duct firing).

    [Application No. 0730003-009-AC; Rule 62-210.200(PTE), F.A.C.]

11. Authorized Methods of Operation:

    a. *Combined Cycle Operation*: When operating as a combined cycle unit, the combustion turbine is authorized to fire natural gas or distillate oil and operate the gas-fired duct burners. For this permit, "combined cycle" shall mean operation of the combustion turbine during which heat is recovered from the combustion turbine exhaust in the HRSG to generate steam. This includes operation when the HRSG and SCR system are functioning, but the steam produced is dumped to a condenser.

b. *Simple Cycle HRSG/SCR Bypass Operation*: The combustion turbine shall fire only natural gas with no duct firing when operating as a simple cycle unit with the exhaust bypassing the HRSG and SCR system. To operate in this manner, the unit must be cooled and a blanking plate installed to direct exhaust gases to the bypass stack. This method of operation will be an infrequent occurrence, most likely due to problems or maintenance of the HRSG, SCR system or steam turbine-electrical generator system.

[Application No. 0730003-009-AC]

EMISSIONS STANDARDS

12. Emissions Standards: Emissions from the combined cycle unit shall not exceed the following standards.

Pollutant	Fuel	Operating Method [a]	Emission Standard ppmvd @ 15% O_2	Equivalent lb/hour [b]	Averaging Period	Compliance Method
CO [c]	Gas	Combined Cycle	16.8	96.8	30-day rolling avg.	CO CEMS
		SC/Bypass	10.0	41.7	4-hour test avg.	EPA Method 10 [e]
	Oil	Combined Cycle	21.4	142.9	30-day rolling avg.	CO CEMS
	All Fuels	All methods	340.10 tons	---	12-month rolling total	CO CEMS
NOx [d]	Gas	Combined Cycle	5.0	47.8	30-day rolling avg. [c]	NOx CEMS
		SC/Bypass	9.0	61.8	4-hour test avg.	EPA Method 7E [e]
	Oil	Combined Cycle	10.0	108.4	30-day rolling avg. [c]	NOx CEMS
Opacity	All Fuels	All Methods	10 % Opacity		6-minute block avg.	EPA Method 9

a. "SC/Bypass" means operation as a simple cycle unit with the blanking plate installed to bypass the HRSG and SCR system and exhaust directly to the bypass stack.

b. Mass emissions rates represent the maximum equivalent "lb/hour" for the highest emitting method of operation, which includes duct firing for most cases. Mass emissions rates are based on a compressor inlet temperature of 25° F and the higher heating value of each fuel. Maximum mass emission rates will vary based on the actual test conditions in accordance with the performance curves and/or equations. For the combustion turbine, it is not necessary to continuously report hourly mass emissions rates with the CEMS data. See Appendix F for a summary of equivalent mass emissions rates.

c. To determine compliance with the emissions standards based on a 30-day rolling average, each fuel will have a separate 30-day rolling emissions standard based on CEMS data. To determine compliance with the CO emissions cap based on a 12-month rolling total, the mass emissions rate shall be determined from all valid hourly emissions data including periods such as startup, shutdown, malfunction, fuel switching, and tuning. Mass emissions may be determined from the CEMS data by using the appropriate F-Factor for each fuel.

d. To determine compliance with the NOx emissions standards based on a 30-day rolling average, each fuel will have a separate 30-day rolling emissions standard based on NOx CEMS data.

e. In addition to the methods specified above, data gathered by the CO CEMS and NOx CEMS may be used to demonstrate compliance in accordance with Conditions 26 and 27 in this section.

{Permitting Note: Potential annual emissions from the combustion turbine system are: 340 tons/year of CO, 332 tons/year of NOx, 112 tons/year of PM/PM_{10}, 212 tons/year of SO_2, 40 tons/year of SAM, and 47 tons/year of VOC.

Note that the project requires the shutdown of the existing Unit 2 boiler, which provided emissions decreases and allowed the project to avoid PSD preconstruction review. Potential annual emissions are based on: the permitted emissions standards; the operational restrictions in the permit; a maximum heat input rate from firing natural gas of 1795 MMBtu per hour at compressor inlet temperature of 59° F; and a maximum heat input rate from firing distillate oil of 1979 MMBtu per hour at compressor inlet temperature of 59° F.}

[Application No. 0730003-009-AC; Rule 62-4.070(3), F.A.C; Rule 62-212.400(12)(Source Obligation), F.A.C. for the CO Emissions Cap]

13. Ammonia Slip: The SCR system shall be designed to achieve a maximum ammonia slip of 5 ppmvd @ 15% oxygen. Actual ammonia slip levels shall not exceed 10 ppmvd @ 15% oxygen as determined by EPA Method CTM-027 based on the average of three test runs. If tests indicate an ammonia slip level greater than 5 ppmvd @ 15% oxygen, the permittee shall:

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

    b. Before the ammonia slip exceeds 10 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

    c. Test and demonstrate that the ammonia slip is less than 5 ppmvd corrected to 15% oxygen within 45 days after completing the corrective actions.

    Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

14. Applicable NSPS Provisions: In addition to the above standards, the combustion turbine system shall be designed, operated, and maintained to achieve the following federal New Source Performance Standards (NSPS) in 40 CFR 60: Subpart A (General Provisions) and Subpart KKKK (New Combustion Turbines and Duct Burners). In summary the emissions standards are:

    a. Pursuant to §60.4320 and Table 1, the NSPS Subpart KKKK NOx standard for gas firing is 15 ppmvd @ 15% oxygen based on a 30-day rolling average for combined cycle operation and 15 ppmvd @ 15% oxygen based on a 4-hour rolling average for simple cycle HRSG/SCR bypass operation.

    b. Pursuant to §60.4320 and Table 1, the NSPS Subpart KKKK NOx standard for oil firing is 42 ppmvd @ 15% oxygen based on a 30-day rolling average for combined cycle operation.

    c. Pursuant to §60.4330(a)(2), SO_2 emissions are limited in NSPS Subpart KKKK by a prohibition on the firing of any fuels that contain total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input.

    See Appendix D of this permit for the full NSPS requirements. [40 CFR 60, Subparts A and KKKK]

15. Applicable NESHAP Provisions: In addition to the above standards, the combustion turbine system shall be designed, operated, and maintained to achieve the following federal National Emissions Standards for Hazardous Air Pollutants (NEHSAP) in 40 CFR 63: Subpart A (General Provisions) and Subpart YYYY (Combustion Turbines). *{Permitting Note: On August 18, 2004, EPA stayed the effectiveness of NESHAP Subpart YYYY for lean premix and diffusion flame combustion turbines. When the stay is lifted, the regulation may be revised. It is uncertain at this time whether or not the combustion turbine will be subject to a formaldehyde limit with emissions testing or an oxidation catalyst will be required or some other set of requirements.}* [40 CFR 63, Subparts A and YYYY]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition 12 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal NSPS, NESHAP, or Acid Rain provision.}

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. [Rule 62-210.700(4), F.A.C.]

17. 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.

18. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, malfunction, fuel switches, and DLN/SCR/WI tuning are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such events. For excess emissions events that last less than the maximum duration allowed, only those minutes attributable to excess emissions from the event shall be excluded. When authorized, excess emissions data shall be excluded from a compliance determination as a continuous block attributed to the event.

    a. *Startup*:

        1) Steam Turbine Generator Cold Startup: No more than the first 600 minutes of CEMS data shall be excluded due to excess emissions from a steam turbine generator cold startup. A "steam turbine generator cold startup" is defined as startup after the steam turbine generator has been offline for 24 hours or more, or the first stage turbine metal temperature is 250°F or less.

        2) Steam Turbine Generator Warm Startup: No more than the first 300 minutes of CEMS data shall be excluded due to excess emissions from a steam turbine generator warm startup. A "steam turbine generator warm startup" is defined as startup to combined cycle operation when the gas turbine has been shut down for a period of time and the first stage steam turbine metal temperature is greater than 250°F.

        3) Steam Turbine Generator Hot Startup: No more than the first 240 minutes of CEMS data shall be excluded due to excess emissions from a steam turbine generator hot startup. A "steam turbine generator hot startup" is defined as startup of the steam turbine generator while the unit has been operating in the combined cycle mode with the steam being dumped to the condenser.

        4) Simple Cycle HRSG/SCR Bypass Startup: No more than the first 30 minutes of CEMS data shall be excluded due to excess emissions from a simple cycle gas turbine startup in which exhaust is directed to the HRSG/SCR bypass stack.

    b. *Shutdown*: No more than the first 30 minutes of CEMS data shall be excluded due to excess emissions from a combustion turbine shutdown. For shutdowns of less than 30 minutes in duration, only those minutes attributable to excess emissions from shutdown shall be excluded.

    c. *Malfunction*: No more than 120 minutes of CEMS data shall be excluded in a 24-hour period due to excess emissions from malfunction. 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.

    d. *Fuel Switch*: No more than the first 30 minutes of CEMS data shall be excluded due to excess emissions from a fuel switch. For fuel switches less than 30 minutes in duration, only those minutes attributable to excess emissions from fuel switching shall be excluded.

    e. *DLN/SCR/WI Tuning*: No more than 72 hours of CEMS data during any consecutive 12 months shall be excluded from the CEMS compliance demonstration due to excess emissions from the necessary tuning of the dry low-NOx (DLN) combustion system, the selective catalytic reduction (SCR) system, or the water injection (WI) system. Tuning sessions shall be performed in accordance with the manufacturer's recommendations or industry standards. Prior to performing any DLN, SCR, or WI tuning session, the permittee shall provide the Compliance Authority with an advance notice (telephone, facsimile transmittal, or electronic mail) that details the activity and proposed tuning schedule. *{Permitting Note: DLN tuning sessions are typically required after completion of initial construction, a combustor change-out, a major repair, a unit overhaul, maintenance to a combustor, or other similar circumstances. During DLN or water injection tuning, the SCR system is turned off and the combustion* *turbine is sequentially stepped through numerous loads (including low load levels) to gather actual emissions data and operational information for use in adjusting the combustion turbine and control system.}*

CEMS data shall only be excluded in accordance with the procedures described in the Condition 21 of this section (CEMS Data Requirements). As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for the specifically defined periods. Data exclusion does not apply to the CO emissions cap based on a 12-month rolling total. [Application No. 0730003-009-AC; Design; Rule 62-210.700(5), F.A.C.]

19. Alternate Visible Emissions Standard: Visible emissions due to startup shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-210.700(5), F.A.C.]

CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) REQUIREMENTS

20. CEMS: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NOx from the combustion turbine HRSG exhaust stack in a manner sufficient to demonstrate continuous compliance with the CEMS-based emission standards of this section. Within 60 days of achieving permitted capacity, but no later than 180 days after first fire, all continuous emissions monitoring systems shall be installed, certified and functioning properly.

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

    b. *NOx Monitor:* The 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 RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

    c. *Diluent 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. The monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

    [Rules 62-4.070(3), 62-210.800, and 62-297.520, F.A.C.]

21. CEMS Data Requirements: The CEMS shall be installed, calibrated, maintained, and operated in the combustion turbine exhaust stacks to measure and record the emissions of CO, and NOx in a manner sufficient to demonstrate compliance with the CEMS-based emission limits standards of this section. The CEMS shall express the results in units of ppmvd corrected to 15% oxygen.

    a. *Valid Hourly Averages for Compliance:* 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. Except for allowable emissions data exclusions, 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. Each 1-hour block average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, there is insufficient data and the 1-hour block average is not valid. Also, if an allowable exclusion episode should occur over two separate hourly averages, only those minutes attributed to the specific episode shall be excluded from each hour.

    b. *30-day Rolling Averages*: A 30-day rolling average shall be calculated from all valid hourly averages collected during the given operating day and the previous 29 operating days. For purposes of determining compliance with the 30-day rolling NOx standard, the missing data substitution methodology of 40 CFR Part 75, Subpart D, shall not be utilized. Instead, the 30-day rolling average shall be determined using the remaining hourly data and periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance reports. *{Permitting Note: Condition 22 defines the use of "maximum permitted emission levels" for* *use when the combustion turbine operates in simple cycle mode.}*

c. *12-Month Rolling Total*: By the end of each month, the CO CEMS shall also determine a 12-month rolling total of CO emissions from the combustion turbine. The 12-month rolling total shall be based on all valid CO CEMS data collected (including startups, shutdowns, and malfunctions) for the given month and the previous 11 months.

d. *Data Exclusion*: Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall monitor and record emissions during all operations including episodes of startups, shutdowns, malfunctions, and DLN tuning. Limited amounts of CEMS emissions data recorded during some of these episodes may be excluded from the corresponding compliance demonstration subject to the provisions of Condition 18 in this section. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable.

e. *Monitor Availability*. Monitor availability for each CEMS used to demonstrate compliance shall be 95% or greater in any calendar quarter. Monitor availability shall be calculated consistent with Subpart KKKK in 40 CFR 60 and reported in the SIP and NSPS excess emissions reports required in Condition 36. In the event that 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Compliance Authority.

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

22. Simple Cycle HRSG/SCR Bypass Operation: Because the bypass stack will only be used in emergency situations where the HRSG, SCR and/or steam turbine-generator are unavailable, the permittee is not required to install CO/NOx CEMS or permanent test ports on the bypass stack. When an emergency situation occurs, the permittee shall ensure that the unit is firing only natural gas and is properly operating with lean premix combustion (Mode 6). The permittee shall monitor the hours of operation in simple cycle HRSG/SCR bypass mode and use the following methods to determine CO and NOx emissions.

    a. Compliance with the NOx and CO emission standards for the simple cycle HRSG/SCR bypass mode of operation shall be demonstrated by conducting initial and annual tests as required by Condition 26 of this section.

    b. Compliance with the 12-month rolling CO emissions cap, the maximum CO mass emission rate of 41.7 lb/hour shall be used to represent each hour of operation in this mode.

    If the unit operates in simple cycle mode for a substantial period of time, the Compliance Authority may request additional CO and NOx testing to demonstrate compliance with the standards. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

    {Permitting Note: The above sampling method is similar to the method allowed under the Acid Rain program for bypass stack situations as described in 40 CFR 75.17(d)(2).}

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

EMISSIONS PERFORMANCE TESTING

24. Continuous Compliance: Continuous compliance with the CO and NOx emissions standards shall be demonstrated with data collected from the required continuous emissions monitoring systems (CEMS). The permittee shall submit an initial compliance report in accordance with Condition 30 of this section. [Rules 62-4.070(3) and 62-297.310(7)(a) and (b), F.A.C.]

25. Operational Rate During Testing: Initial and subsequent performance tests shall be conducted between 90% and 100%

of permitted capacity for the given compressor inlet conditions in accordance with the requirements of Rule 62-297.310(2), F.A.C. [Rule 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

26. Initial Compliance Tests: In accordance with the test methods specified in this section, 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.

    a. The HRSG stack shall be tested on each authorized fuel in combined cycle mode to demonstrate compliance with the standards for ammonia slip and visible emissions. For each required test, emissions of CO and NOx recorded by the CEMS shall also be reported.

    b. The simple cycle HRSG/SCR bypass operation shall be tested when firing natural gas in simple cycle mode to demonstrate compliance with the permitted CO and NOx emissions standards. For this method of operation, tests may be conducted by taking the SCR system out of service and sampling at the HRSG stack. In addition, the installed and certified CO and NOx CEMS may be used to provide the compliance test data. These tests shall consist of at least four, 1-hour test runs to determine the 4-hour average.

    [Rules 62-4.070(3) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

27. Annual Compliance Testing: During each federal fiscal year (October 1st to September 30th), annual compliance tests shall be conducted in accordance with the test method specified in this section.

    a. The HRSG stack shall be tested on natural gas in combined cycle mode to demonstrate compliance with the standards for ammonia slip and visible emissions. For each required test, emissions of CO and NOx recorded by the CEMS shall also be reported. If distillate oil is fired for more than 400 hours during the federal fiscal year, the HRSG stack shall also be tested on oil in combined cycle mode to demonstrate compliance with the standards for ammonia slip and visible emissions.

    b. The simple cycle HRSG/SCR bypass operation shall be tested when firing natural gas in simple cycle mode to demonstrate compliance with the permitted CO and NOx emissions standards. For this method of operation, tests may be conducted by taking the SCR system out of service and sampling at the HRSG stack. In addition, the installed and certified CO and NOx CEMS may be used to provide the compliance test data. These tests shall consist of at least four, 1-hour test runs to determine the 4-hour average.

    [Rules 62-4.070(3) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

28. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. [Rule 62-297.310(7)(a)9, F.A.C.]

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

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental)
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

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 Department. Tests shall be conducted in accordance with the appropriate test method, the applicable requirements specified in Appendix C of this permit, and the applicable NSPS and NESHAP in 40 CFR Parts 60 and 63, respectively. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR Parts 60 and 63]

REPORTING AND RECORD KEEPING REQUIREMENTS

30. CEMS Report - Initial Operation: For the first two calendar quarters of operation, the permittee shall submit a report summarizing the CO and NOx emissions as determined by CEMS data. Emissions rates shall be reported in terms of

ppmvd @ 15% oxygen for the 30-day rolling averages. CO emissions shall also be reported in "tons per month". Reports shall be submitted within 30 days of each calendar quarter. [Rule 62-4.070(3), F.A.C.]

31. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the combustion turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, and DLN tuning). 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 system required above. [Rule 62-4.070(3), F.A.C.; 40 CFR 75]

32. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the previous month and the previous consecutive 12 months: total heat input rate to the combustion turbine from each fuel (MMBtu); the total heat input rate to the duct burner (MMBtu); and the 12-month rolling total of CO emissions (tons). 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. Fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3), F.A.C.]

33. Fuel Sulfur Records: The sulfur content of the distillate oil shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. For each fuel oil delivery, the permittee shall record and retain the following information: the date; gallons delivered; and a fuel oil analysis including the heat content in MMBtu/gallon, the density in pounds/gallon, the sulfur content in percent by weight, and the name of the test method used. A certified analysis supplied by the fuel oil vendor is acceptable. Alternatively, the monitoring methods specified in § 60.4370 are sufficient to demonstrate compliance with the maximum fuel sulfur levels for distillate oil established in this permit. [Rule 62-4.070(3), F.A.C.; 40 CFR 60.4370]

34. Stack Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Compliance Authority to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the applicable information specified in Rule 62-297.310(8), F.A.C. and summarized in Appendix C. [Rule 62-297.310(8), F.A.C.]

35. CEMS RATA Reports: At least 15 days prior to conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall notify the Compliance Authority of the schedule (letter, email, fax, or phone call). In addition to filing reports with the Department's Bureau of Air Monitoring and Mobile Sources, a summary of the RATA reports shall be submitted to the Compliance Authority within 45 days of completing the RATA. [Rules 62-4.070(3), F.A.C.]

36. Excess Emissions Reporting

    a. *Malfunction Notification:* If NOx data will be excluded due to a malfunction, the permittee shall notify the Compliance Authority within one 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 Compliance Authority may request a written summary report of the incident.

    b. *SIP Excess Emissions Report*: Within 30 days following the end of June and December of each year, the permittee shall submit a report to the Compliance Authority summarizing the following for the combustion turbine for the period: a summary of the CO and NOx compliance periods; a summary of CO and NOx data excluded due to malfunctions; a summary of the 12-month rolling CO emissions totals; a summary of any RATA tests performed; and a summary of the CEMS systems monitor availability for each quarter during the period.

    c. *NSPS Excess Emissions Reports*: Within thirty (30) days following the end of June and December of each year, the permittee shall submit a report including any applicable periods of excess emissions and monitoring systems performance as defined in 40 CFR 60 Subpart KKKK that occurred during the previous semi-annual period to the Compliance Authority. *{Permitting Note: If there are no periods of excess emissions as defined in Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}*

[Rules 62-4.070(3), 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7, 60.4375, and 60.4395]

37. Initial Report on Startups: The permittee shall submit a report summarizing the following information for each startup during the first 12 months of operation: the type of startup; the sequence of events for the startup; the duration of the startup; CO and NOx hourly emissions averages recorded for each hour of the startup (lb/hour and ppmvd @ 15% oxygen); total CO and NOx mass emissions rates for each startup (pounds). The report is due within 60 days following the 12th month of operation for the unit. Based on the actual information, the Department may reduce the duration of data allowed to be excluded as excess emissions due to the startup event through an air construction permit modification. [Rules 62-4.070(3) and 62-210.700(5), F.A.C.]

CONTENTS

CITATION FORMATS

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

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

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

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

New Permit Numbers

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

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

PSD Permit Numbers

Example: Permit No. PSD-FL-317

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

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology (Not Applicable);
    b. Determination of Prevention of Significant Deterioration (Not Applicable); and
    c. Compliance with New Source Performance Standards (Not 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.

{Permitting Note: Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.}

EMISSIONS AND CONTROLS

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

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

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

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

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

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

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

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]

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

TESTING REQUIREMENTS

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

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

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

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

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

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

14. Determination of Process Variables

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

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

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

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

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

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

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

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

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

RECORDS AND REPORTS

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

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

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

On July 6, 2006, EPA published the final NSPS Subpart KKKK (40 CFR 60) provisions for combustion turbines in the Federal Register. Although not yet adopted by Rule 62-204.800(8), F.A.C., the combustion turbine shall comply with the applicable federal requirements.

NSPS SUBPART A, 40 CFR 60 - GENERAL PROVISIONS

The permittee shall comply with the applicable general provisions identified in Table 7 of 40 CFR 63 Subpart YYYY.

NSPS SUBPART KKKK, 40 CFR 60 – STATIONARY COMBUSTION TURBINES

Provisions that do not apply to this project have been omitted. Numbering remains consistent with the NSPS Subpart.

Sec. 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.

Sec. 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.

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

No applicable provisions.

Sec. 60.4315 What pollutants are regulated by this subpart?

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

Sec. 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.

Sec. 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.

Sec. 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.

   (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.

Sec. 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.

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

(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); and

Sec. 60.4340 How do I demonstrate continuous compliance for NOx if I do not use water or steam injection?

(a) *Simple Cycle HRSG/SCR Bypass Operation (for this project):* If you are not using water or steam injection to control NOx emissions, you must perform annual performance tests in accordance with Sec. 60.4400 to demonstrate continuous compliance. If the NOx emission result from the performance test is less than or equal to 75 percent of the NOx 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 NOx 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 Sec. 60.4335(b) and Sec. 60.4345 *for combined cycle operation for this project.*

(2) Continuous parameter monitoring *for simple cycle HRSG/SCR bypass operation for this project* as follows:

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOx mode.

Sec. 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 Sec. 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 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.

(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.

Sec. 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 Sec. 60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in Sec. 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 Sec. 60.7(c).

(e) All required fuel flow rate data must be reduced to hourly averages.

(f) Calculate the hourly average NOx emission rates, in units of the emission standards under Sec. 60.4320, using either ppm for units complying with the concentration limit.

(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 Sec. 60.4380(b)(1).

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

(a) The parameters that are continuously monitored as described in Sec. Sec. 60.4335 and 60.4340 must be monitored during the performance test required under Sec. 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 NOx 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 NOx 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.

(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.

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

No applicable provisions.

Sec. 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 tariff sheet or specifying that the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet; 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.

Sec. 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 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., 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).

Sec. 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 Sec. 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 Sec. 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.

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

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

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

(1) An excess emissions is any unit operating period in which the 30-day rolling average NOx emission rate exceeds the applicable emission limit in Sec. 60.4320. For the purposes of this subpart, a "30-day rolling average NOx emission rate" is the arithmetic average of all hourly NOx 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 NOx emissions rates for the preceding 30 unit operating days if a valid NOx 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: NOx concentration, CO_2 or O_2 concentration, fuel flow rate.

(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 NOx 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.

Sec. 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:

(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.

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

No applicable provisions.

(a) If you operate an emergency combustion turbine, you are exempt from the NOx 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 NOx limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

Sec. 60.4395 When must I submit my reports?

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

Sec. 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 Sec. 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) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NOx concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part.

(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 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 NOx concentration during the stratification test; or

(B) For Turbines with a NOx standard greater than 15ppm @ 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 3ppm or 0.3 percent CO2 (or O2) from the mean for all traverse points; or

(C) For turbines with a NOx standard less than or equal 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 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 NOx emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(4) Compliance with the applicable emission limit in Sec. 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 Sec. 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 Sec. 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.

Sec. 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 NOX-diluent CEMS under Sec. 60.4345, then the initial performance test required under Sec. 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.

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

(d) Compliance with the applicable emission limit in Sec. 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.

Sec. 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 NOx emission controls in accordance with Sec. 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 Sec. 60.4355.

Sec. 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 Sec. 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 Sec. 60.17) for natural gas or ASTM D4177 (incorporated by reference, see Sec. 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 Sec. 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 Sec. 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 Sec. 60.17).

(b) [Reserved]

Sec. 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.

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.

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.

Excess emissions means a specified averaging period over which either (1) the NOx emissions are higher than the applicable emission limit in Sec. 60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in Sec. 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.

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 Stationary Combustion Turbines

Combustion Turbine Type	Combustion Turbine Heat Input Rate at Peak Load (HHV)	NOx Emission Standard
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, 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)

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP)

New combustion turbines are subject to the NESHAP provisions of Subpart YYYY in 40 CFR 63. However, on August 18, 2004, EPA stayed the effectiveness of NESHAP Subpart YYYY for lean premix and diffusion flame gas turbines. The relevant provision of the rule that stays the effectiveness for such units is as follows.

40 CFR 63.6095(d) Stay of Standards for Gas-Fired Subcategories.

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

NESHAP SUBPART A, 40 CFR 63 - GENERAL PROVISIONS

The permittee shall comply with the applicable general provisions identified in Table 7 of 40 CFR 63 Subpart YYYY.

NESHAP SUBPART YYYY – STATIONARY COMBUSTION TURBINES

40 CFR 63.6080 What is the purpose of subpart YYYY?

Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

40 CFR 63.6085 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions.

(a) *No applicable requirements.*

(b) A major source of HAP emissions is a contiguous site under common control that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

40 CFR 63.6090 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) Affected source. An affected source is any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions.

    (2) New stationary combustion turbine. A stationary combustion turbine is new if you commenced construction of the stationary combustion turbine after January 14, 2003.

(b) *No applicable requirements.*

40 CFR 63.6092 Are duct burners and waste heat recovery units covered by subpart YYYY?

No, duct burners and waste heat recovery units are considered steam generating units and are not covered under this subpart. In some cases, it may be difficult to separately monitor emissions from the turbine and duct burner, so sources are allowed to meet the required emission limitations with their duct burners in operation.

40 CFR 63.6095 When do I have to comply with this subpart?

(a) Affected sources.

    (1) *No applicable requirements.*

(2) If you start up a new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart after March 5, 2004, you must comply with the emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *No applicable requirements.*

(c) You must meet the notification requirements in Sec. 63.6145 according to the schedule in Sec. 63.6145 and in 40 CFR part 63, subpart A.

40 CFR 63.6100 What emission and operating limitations must I meet?

For each new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart, you must comply with the emission limitations and operating limitations in Table 1 and Table 2 of this subpart.

40 CFR 63.6105 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations which apply to you at all times except during startup, shutdown, and malfunctions.

(b) If you must comply with emission and operating limitations, you must operate and maintain your stationary combustion turbine, oxidation catalyst emission control device or other 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.

40 CFR 63.6110 By what date must I conduct the initial performance tests or other initial compliance demonstrations?

(a) You must conduct the initial performance tests or other initial compliance demonstrations in Table 4 of this subpart that apply to you within 180 calendar days after the compliance date that is specified for your stationary combustion turbine in Sec. 63.6095 and according to the provisions in Sec. 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test to determine outlet formaldehyde concentration on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (b)(5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

40 CFR 63.6115 When must I conduct subsequent performance tests?

Subsequent performance tests must be performed on an annual basis as specified in Table 3 of this subpart.

40 CFR 63.6120 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Table 3 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements of the General Provisions at Sec. 63.7(e)(1) and under the specific conditions in Table 2 of this subpart.

(c) Do not conduct performance tests or compliance evaluations during periods of startup, shutdown, or malfunction. Performance tests must be conducted at high load, defined as 100 percent plus or minus 10 percent.

(d) You must conduct three separate test runs for each performance test, and each test run must last at least 1 hour.

(e) If your stationary combustion turbine is not equipped with an oxidation catalyst, you must petition the Administrator for operating limitations that you will monitor to demonstrate compliance with the formaldehyde emission limitation in Table 1. You must measure these operating parameters during the initial performance test and continuously monitor thereafter. Alternatively, you may petition the Administrator for approval of no additional operating limitations. If you submit a petition under this section, you must not conduct the initial performance test until after the petition has been approved or disapproved by the Administrator.

(f) If your stationary combustion turbine is not equipped with an oxidation catalyst and you petition the Administrator for approval of additional operating limitations to demonstrate compliance with the formaldehyde emission limitation in Table 1, your petition must include the following information described in paragraphs (f)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as additional operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(g) If you petition the Administrator for approval of no additional operating limitations, your petition must include the information described in paragraphs (g)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary combustion turbine and any emission control device which could change intentionally (e.g., operator adjustment, automatic controller adjustment, etc.) or unintentionally (e.g., wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of why establishing limitations on the parameters is not possible;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of why you could not establish upper and/or lower values for the parameters which would establish limits on the parameters as operating limitations;

(5) For the parameters which could change in such a way as to increase HAP emissions, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible, unreasonable or unnecessary to adopt the parameters as operating limitations.

40 CFR 63.6125 What are my monitor installation, operation, and maintenance requirements?

(a) *No applicable requirements.*

(b) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you are not using an oxidation catalyst, you must continuously monitor any parameters specified in your approved petition to the Administrator, in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.

(c) *No applicable requirements.*

(d) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must monitor and record your distillate oil usage daily for all new and existing stationary combustion turbines located at the major source with a non-resettable hour meter to measure the number of hours that distillate oil is fired.

40 CFR 63.6130 How do I demonstrate initial compliance with the emission and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 4 of this subpart.

(b) You must submit the Notification of Compliance Status containing results of the initial compliance demonstration according to the requirements in Sec. 63.6145(f).

40 CFR 63.6135 How do I monitor and collect data to demonstrate continuous compliance?

(a) Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), you must conduct all parametric monitoring at all times the stationary combustion turbine is operating.

(b) Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. You must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine.

40 CFR 63.6140 How do I demonstrate continuous compliance with the emission and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Table 1 and Table 2 of this subpart according to methods specified in Table 5 of this subpart.

(b) You must report each instance in which you did not meet each emission imitation or operating limitation. You must also report each instance in which you did not meet the requirements in Table 7 of this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in Sec. 63.6150.

(c) Consistent with Sec. 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, and malfunction are not violations if you have operated your stationary combustion turbine in full conformity with all provisions of your startup, shutdown, and malfunction plan, and you have otherwise satisfied the general duty to minimize emissions established by Sec. 63.6(e)(1)(i).

40 CFR 63.6145 What notifications must I submit and when?

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

(b) *No applicable requirements.*

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

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

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

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

40 CFR 63.6150 What reports must I submit and when?

(a) Anyone who owns or operates a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report according to Table 6 of this subpart. The semiannual compliance report must contain the information described in paragraphs (a)(1) through (a)(4) of this section. The semiannual compliance report must be submitted by the dates specified in paragraphs (b)(1) through (b)(5) of this section, unless the Administrator has approved a different schedule.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) For each deviation from an emission limitation, the compliance report must contain the information in paragraphs (a)(4)(i) through (a)(4)(iii) of this section.

(i) The total operating time of each stationary combustion turbine during the reporting period.

(ii) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(iii) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(b) Dates of submittal for the semiannual compliance report are provided in (b)(1) through (b)(5) of this section.

(1) The first semiannual compliance report must cover the period beginning on the compliance date specified in Sec. 63.6095 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date specified in Sec. 63.6095.

(2) The first semiannual compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified in Sec. 63.6095.

(3) Each subsequent semiannual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent semiannual compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports

according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) *No applicable requirements.*

(d) *No applicable requirements.*

(e) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must submit an annual report according to Table 6 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (d)(1) through (5) of this section. You must report the data specified in (e)(1) through (e)(3) of this section.

(1) The number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

40 CFR 63.6155 What records must I keep?

(a) You must keep the records as described in paragraphs (a)(1) through (5).

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirements in Sec. 63.10(b)(2)(xiv).

(2) Records of performance tests and performance evaluations as required in Sec. 63.10(b)(2)(viii).

(3) Records of the occurrence and duration of each startup, shutdown, or malfunction as required in Sec. 63.10(b)(2)(i).

(4) Records of the occurrence and duration of each malfunction of the air pollution control equipment, if applicable, as required in Sec. 63.10(b)(2)(ii).

(5) Records of all maintenance on the air pollution control equipment as required in Sec. 63.10(b)(iii).

(b) If you are operating a stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis, or if you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must keep the records of your daily fuel usage monitors.

(c) You must keep the records required in Table 5 of this subpart to show continuous compliance with each operating limitation that applies to you.

40 CFR 63.6160 In what form and how long must I keep my records?

(a) You must maintain all applicable records in such a manner that they can be readily accessed and are suitable for inspection according to Sec. 63.10(b)(1).

(b) As specified in Sec. 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must retain your records of the most recent 2 years on site or your records must be accessible on site. Your records of the remaining 3 years may be retained off site.

40 CFR 63.6165 What parts of the General Provisions apply to me?

Table 7 of this subpart shows which parts of the General Provisions in Sec. 63.1 through 15 apply to you.

40 CFR 63.6170 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under section 40 CFR Part 63, Subpart E, the authorities contained in paragraph (c) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the emission limitations or operating limitations in Sec. 63.6100 under Sec. 63.6(g).

(2) Approval of major alternatives to test methods under Sec. 63.7(e)(2)(ii) and (f) and as defined in Sec. 63.90.

(3) Approval of major alternatives to monitoring under Sec. 63.8(f) and as defined in Sec. 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under Sec. 63.10(f) and as defined in Sec. 63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule to determine outlet formaldehyde concentration, as specified in Sec. 63.6110(b).

40 CFR 63.6175 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA; in 40 CFR 63.2, the General Provisions of this part; and in this section:

Area source means any stationary source of HAP that is not a major source as defined in this part.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary reciprocating internal combustion engines.

CAA means the Clean Air Act (42 U.S.C. 7401 et seq., as amended by Public Law 101-549, 104 Stat. 2399).

Combined cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger to generate steam for use in a steam turbine.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit;

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless of whether or not such failure is permitted by this subpart; or

(4) Fails to conform to any provision of the applicable startup, shutdown, or malfunction plan, or to satisfy the general duty to minimize emissions established by Sec. 63.6(e)(1)(i).

Diffusion flame oil-fired stationary combustion turbine means:

(1) (i) Each stationary combustion turbine which is equipped only to fire oil using diffusion flame technology, and

(ii) Each stationary combustion turbine which is equipped both to fire oil using diffusion flame technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil.

(2) Diffusion flame oil-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine, or

(ii) Any stationary combustion turbine located on the North Slope of Alaska.

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

Distillate oil means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2.

Hazardous air pollutant (HAP) means any air pollutant listed in or pursuant to section 112(b) of the CAA.

ISO standard day conditions means 288 degrees Kelvin (15<DEGC), 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix gas-fired stationary combustion turbine means:

(1) (i) Each stationary combustion turbine which is equipped only to fire gas using lean premix technology,

(ii) Each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, during any period when it is firing gas, and

(iii) Each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

(2) Lean premix gas-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine,

(ii) Any stationary combustion turbine located on the North Slope of Alaska, or

(iii) Any stationary combustion turbine burning landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or any stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis.

Lean premix oil-fired stationary combustion turbine means:

(1) (i) Each stationary combustion turbine which is equipped only to fire oil using lean premix technology, and

(ii) Each stationary combustion turbine which is equipped both to fire oil using lean premix technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil.

(2) Lean premix oil-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine, or

(ii) Any stationary combustion turbine located on the North Slope of Alaska.

Lean premix technology means a configuration of a stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber.

Major source, as used in this subpart, shall have the same meaning as in Sec. 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in this section, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in this section, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes or has the potential to cause the emission limitations in this standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. May be field or pipeline quality. For the purposes of this subpart, the definition of natural gas includes similarly constituted fuels such as field gas, refinery gas, and syngas.

Oxidation catalyst emission control device means an emission control device that incorporates catalytic oxidation to reduce CO emissions.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in Sec. 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to Sec. 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to Sec. 63.1270(a)(2).

Simple cycle stationary combustion turbine means any stationary combustion turbine that does not recover heat from the stationary combustion turbine exhaust gases.

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), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Tables to Subpart YYYY of Part 63.

As stated in § 63.6100, you must comply with the following emission limitations:

TABLE 1 TO SUBPART YYYY OF PART 63 - EMISSIONS LIMITATIONS

For each new or reconstructed stationary combustion turbine described in § 63.6100 which is	You must meet the following emission limitations
1. a lean premix gas-fired stationary combustion turbine as defined in this subpart, 2. a lean premix oil-fired stationary combustion turbine as defined in this subpart, 3. a diffusion flame gas-fired stationary combustion turbine as defined in this subpart, or 4. a diffusion flame oil-fired stationary combustion turbine as defined in this subpart.	limit the concentration of formaldehyde to 91 ppbvd or less at 15 percent O_2.

As stated in §§ 63.6100 and 63.6140, you must comply with the following operating limitations:

TABLE 2 TO SUBPART YYYY OF PART 63. - OPERATING LIMITATIONS

For	You must
1. Each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is using an oxidation catalyst.	Maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer.
2. Each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is not using an oxidation catalyst.	Maintain any operating limitations approved by the Administrator.

As stated in § 63.6120, you must comply with the following requirements for performance tests and initial compliance demonstrations:

TABLE 3 TO SUBPART YYYY OF PART 63. - REQUIREMENTS FOR PERFORMANCE TESTS AND INITIAL COMPLIANCE DEMONSTRATIONS

You must	Using	According to the following requirements
a. Demonstrate formaldehyde emissions meet the emission limitations specified in Table 1 by a performance test initially and on an annual basis AND.	Test Method 320 of 40 CFR part 63, appendix A; ASTM D6348–03 provided that %R as determined in Annex A5 of ASTM D6348– 03 is equal or greater than 70% and less than or equal to 130%; or other methods approved by the Administrator.	Formaldehyde concentration must be corrected to 15 percent O2, dry basis. Results of this test consist of the average of the three 1 hour runs. Test must be conducted within 10 percent of 100 percent load.
b. Select the sampling port location and the number of traverse points AND.	Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	If using an air pollution control device, the sampling site must be located at the outlet of the air pollution control device.
c. Determine the O_2 concentration at the sampling port location AND.	Method 3A or 3B of 40 CFR part 60, appendix A.	Measurements to determine O_2 concentration must be made at the same time as the performance test.
d. Determine the moisture content at the sampling port location for the purposes of correcting the formaldehyde concentration to a dry basis.	Method 4 of 40 CFR part 60, appendix A or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.	Measurements to determine moisture content must be made at the same time as the performance test.

As stated in §§ 63.6110 and 63.6130, you must comply with the following requirements to demonstrate initial compliance with emission limitations:

TABLE 4 TO SUBPART YYYY OF PART 63. - INITIAL COMPLIANCE WITH EMISSION LIMITATIONS

For the	You have demonstrated initial compliance if
Emission limitation for formaldehyde.	The average formaldehyde concentration meets the emission limitations specified in Table 1.

As stated in §§ 63.6135 and 63.6140, you must comply with the following requirements to demonstrate continuing compliance with operating limitations:

TABLE 5 OF SUBPART YYYY OF PART 63. - CONTINUOUS COMPLIANCE WITH OPERATING LIMITATIONS

For each stationary combustion turbine complying with the emission limitation for formaldehyde	You must demonstrate continuous compliance by
1. With an oxidation catalyst	Continuously monitoring the inlet temperature to the catalyst and maintaining the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer.
2. Without the use of an oxidation catalyst	Continuously monitoring the operating limitations that have been approved in your petition to the Administrator.

As stated in § 63.6150, you must comply with the following requirements for reports:

TABLE 6 OF SUBPART YYYY OF PART 63. - REQUIREMENTS FOR REPORTS

If you own or operate a	You must	According to the following requirements
1. Stationary combustion turbine which must comply with the formaldehyde emission limitation.	report your compliance status	semiannually, according to the requirements of § 63.6150.
2. Stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis.	Report: (1) the fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas, digester gas, or gasified MSW is equivalent to 10 percent or more of the gross heat input on an annual basis, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters.	annually, according to the requirements in § 63.6150.
3. A lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source.	Report: (1) the number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters.	annually, according to the requirements in § 63.6150.

TABLE 7 OF SUBPART YYYY OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART YYYY

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.1	General applicability of the General Provisions.	Yes	Additional terms defined in §63.6175.
§63.2	Definitions	Yes	Additional terms defined in §63.6175.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources.	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved].		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major.	Yes.	
§63.6(c)(1)–(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)–(4)	[Reserved].		
§63.6(c)(5)	Compliance dates for existing area sources that become major.	Yes.	
§63.6(d)	[Reserved].		
§63.6(e)(1)	Operation and maintenance	Yes.	
§63.6(e)(2)	[Reserved].		
§63.6(e)(3)	SSMP	Yes.	
§63.6(f)(1)	Applicability of standards except during startup, shutdown, or malfunction (SSM).	Yes.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)–(3)	Use of alternative standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart YYYY does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria.	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)–(2)	Performance test dates	Yes	Subpart YYYY contains performance test dates at §63.6110.
§63.7(a)(3)	Section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes.	
§63.7(b)(2)	Notification of rescheduling	Yes.	
§63.7(c)	Quality assurance/test plan	Yes.	
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests.	Yes.	
§63.7(e)(2)	Conduct of performance tests and reduction of data.	Yes	Subpart YYYY specifies test methods at §63.6120.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA.	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting.	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart YYYY contains specific requirements for monitoring at §63.6125.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved].		
§63.8(a)(4)	Monitoring for control devices	No.	

TABLE 7 OF SUBPART YYYY OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART YYYY—Continued

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems.	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance.	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§63.8(c)(1)(ii)	Parts for repair of CMS readily available	Yes.	
§63.8(c)(1)(iii)	SSMP for CMS required	Yes.	
§63.8(c)(2)–(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements.	Yes	Except that subpart YYYY does not require continuous opacity monitoring systems (COMS).
§63.8(c)(5)	COMS minimum procedures	No.	
§63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart YYYY does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
§63.8(f)(1)–(5)	Alternative monitoring method	Yes.	
§63.8(f)(6)	Alternative to relative accuracy test	Yes.	
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6135 and 63.6140.
§63.9(a)	Applicability and State delegation of notification requirements.	Yes.	
§63.9(b)(1)–(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
§63.9(c)	Request for compliance extension	Yes.	
§63.9(d)	Notification of special compliance requirements for new sources.	Yes.	
§63.9(e)	Notification of performance test	Yes.	
§63.9(f)	Notification of visible emissions/opacity test.	No	Subpart YYYY does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes.	
§63.9(g)(2)	Notification of use of COMS data	No	Subpart YYYY does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to relative accuracy test audit (RATA) is exceeded.	Yes	If alternative is in use.
§63.9(h)	Notification of compliance status	Yes	Except that notifications for sources not conducting performance tests are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping and reporting.	Yes.	
§63.10(b)(1)	Record retention	Yes.	
§63.10(b)(2)(i)–(iii)	Records related to SSM	Yes.	
§63.10(b)(2)(iv)–(v)	Records related to actions during SSM	Yes.	
§63.10(b)(2)(vi)–(xi)	CMS records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA.	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CMS.	Yes	Except that §63.10(c)(2)–(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart YYYY does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports.	No	Subpart YYYY does not require reporting of startup, shutdowns, or malfunctions.
§63.10(e)(1) and (2)(i)	Additional CMS reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart YYYY does not require COMS.
§63.10(e)(3)	Excess emissions and parameter exceedances reports.	Yes.	

TABLE 7 OF SUBPART YYYY OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART YYYY—Continued

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.10(e)(4)	Reporting COMS data	No	Subpart YYYY does not require COMS.
§63.10(f)	Waiver for recordkeeping and reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

EMISSIONS SUMMARY

The following tables are provided for informational purposes to show the effect of compressor inlet temperature and duct firing on the maximum mass emissions rates. The mass emissions rates were provided in the application for the original air construction permit and represent worst-case potential maximum emissions for the given conditions.

Combined Cycle, Natural Gas Firing - Mass Emissions Rates at 100% Load vs. Compressor Inlet Temperature

Pollutant	Mass Emissions Rates (lb/hour)					
	Combustion Turbine Only			Combustion Turbine w/Duct Burning		
Temperature	25° F	59° F	95° F	25° F	59° F	95° F
CO	41.7	39.1	36.2	96.8	90.3	83.9
NOx [a]	34.3	32.4	30.5	47.8	45.0	42.2
PM/PM_{10}	11.1	11.0	10.9	21.1	20.3	19.6
SO_2	10.5	9.9	9.3	14.7	13.8	13.0
VOC [b]	7.5	7.1	6.7	16.7	15.7	14.7

a. Mass emissions based on a controlled NOx emission level of 5 ppmvd @ 15% oxygen.

b. VOC measured as methane.

Combined Cycle, Distillate Oil Firing - Mass Emissions Rates at 100% Load vs. Compressor Inlet Temperature

Pollutant	Mass Emissions Rates (lb/hour)					
	Combustion Turbine Only			Combustion Turbine w/Duct Burning		
Temperature	25° F	59° F	95° F	25° F	59° F	95° F
CO	87.8	82.2	76.1	142.9	133.4	123.8
NOx [a]	81.4	77.5	72.2	108.4	102.6	95.6
PM/PM_{10}	38.7	37.6	36.2	48.7	47.0	44.9
SO_2	107.0	102.0	95.0	111.0	106.0	99.0
VOC [b]	7.9	7.5	7.0	17.1	16.0	14.9

a. Mass emissions based on a controlled NOx emission level of 10 ppmvd @ 15% oxygen.

b. VOC measured as methane.

Simple Cycle, Natural Gas Firing - Mass Emissions Rates at 100% Load vs. Compressor Inlet Temperature

Pollutant	Mass Emissions Rates (lb/hour)		
	Combustion Turbine Only		
Temperature	25° F	59° F	95° F
CO	41.7	39.1	36.2
NOx [a]	61.8	58.4	55.0
PM/PM_{10}	9.0	9.0	9.0
SO_2	10.5	9.9	9.3
VOC [b]	7.5	7.1	6.7

a. Mass emissions based on a controlled NOx emission level of 9 ppmvd @ 15% oxygen.

b. VOC measured as methane.

Memorandum

Florida Department of Environmental Protection

TO: Joe Kahn, Director of DARM

THROUGH: Trina Vielhauer, Chief of BAR TV

FROM: Jeff Koerner, Air Permitting North Program JK

DATE: September 18, 2006

SUBJECT: Final Air Permit No. 0730003-009-AC
City of Tallahassee, Electric Utilities
Arvah B. Hopkins Generating Station
Tallahassee, Florida
Unit 2 Re-Powering Project

Attached for your review and signature is the final permit for the above referenced project. The permit authorizes construction of a new General Electric 7FA combustion turbine (188 MW) and gas-fired heat recovery steam generator (HRSG) to re-power the existing Hopkins Unit 2 steam turbine-electrical generator set (238 MW). The existing Unit 2 boiler will be permanently shut down as part of this project. The new combined cycle unit includes an SCR system and avoids PSD preconstruction review.

The Public Notice was published in the Tallahassee Democrat on September 1, 2006. The Department received the proof of publication on September 13, 2006. No comments were received on the draft permit package. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed. I recommend your approval of the attached final permit for this project.

Attachments

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Robert McGarrah
Manager of Power Production
City of Tallahassee
2602 Jackson Bluff Road
Tallahassee, Florida 32304

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Ashley Ross
☒ Agent
☐ Addressee

B. Received by (Printed Name) ASHLEY ROSS

C. Date of Delivery 9/20/06

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

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

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

2. Article Number
(Transfer from service label) 7000 1670 0013 3110 1250

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

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

OFFICIAL USE

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Restricted Delivery Fee (Endorsement Required)	
Total Pos	

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Sent To Mr. Robert McGarrah
Manager of Power Production
Street, Apt City of Tallahassee
2602 Jackson Bluff Road
City, State Tallahassee, Florida 32304

PS Form 38 ... uctions

City of Tallahassee
Your Own Utilities℠

300 South Adams Street, Tallahassee, Florida 32301, (850) 891-4YOU (4968), talgov.com

September 6, 2006

Via Email; and
Certified Mail No. 70041160000059346275

Trina Vielhauer
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Mail Station #5505
Tallahassee, Florida 32399-2400

RECEIVED
SEP 13 2006
BUREAU OF AIR REGULATION

Re: Proof of Publication
Public Notice of Intent to Issue Air Construction Permit
Arvah B. Hopkins Generating Station
Draft Permit No. 0730003-009-AC

Dear Ms. Vielhauer:

Pursuant to Rule 62-110.106(5), Florida Administrative Code, please find enclosed proof of publication of the Public Notice of Intent to Issue Air Permit (Public Notice) for the Arvah B. Hopkins Generating Station Draft Air Construction Permit No. 0730003-009-AC. The Public Notice was published in the legal advertisement section of the Tallahassee Democrat on September 1, 2006.

Please do not hesitate to contact me at (850) 891-8851 if you have any questions or require additional information.

Sincerely,

John K. Powell, P.E.
Interim Environmental and Safety Manager

Enclosure

cc: Cynthia Barber, COT
Rob McGarrah, COT
Triveni Singh, COT
John Powell, COT

TALLAHASSEE DEMOCRAT
PUBLISHED DAILY
TALLAHASSEE-LEON-FLORIDA

STATE OF FLORIDA COUNTY OF LEON:
Before the undersigned authority personally appeared Daniel Serrano, who on oath says that he is a Legal Advertising Representative of the Tallahassee Democrat, a daily newspaper published at Tallahassee in Leon County, Florida; that the attached copy of advertising being a Legal Ad in the matter of

PUBLIC NOTICE OF INTENT

in the Second Judicial Circuit Court was published in said newspaper in the issues of:

SEPTEMBER 1, 2006

Affiant further says that the said Tallahassee Democrat is a newspaper published at Tallahassee, in the said Leon County, Florida, and that the said newspaper has heretofore been continuously published in said Leon County, Florida each day and has been entered as second class mail matter at the post office in Tallahassee, in said Leon 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 never paid nor promised any person, firm or coporation any discount, rebate, commission or refund for the purpose of securing this publication in the said newspaper.

DANIEL SERRANO
LEGAL ADVERTISING REPRESENTATIVE

Sworn To or Affirmed and Subscribed Before Me.
This 1 Day of September 2006, by
Daniel Serrano,______________
Personally Known______________
OR Produced Identification______________
Type of Identification Produced______________

(SEAL) Notary Public
State of Florida
County of Leon

CHASMA JAMES
MY COMMISSION # DD 490305
EXPIRES: March 11, 2010
Bonded Thru Notary Public Underwriters

Chasma James

B434774

Legal Notices Legal Notices Legal Notices

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Draft Air Permit No. 0730003-009-AC
Arvah B. Hopkins Generating Station, Unit 2 Re-Powering Project
Leon County, Florida

Applicant: The applicant for this project is the City of Tallahassee. The City of Tallahassee's Authorized Representative is Mr. Robert E. McGarrah, Production Superintendent. The City's mailing address is 2602 Jackson Bluff Road, Tallahassee, Florida 32304.

Facility Location: The City of Tallahassee operates the existing Arvah B. Hopkins Generating Station, which is located in Leon County at 1125 Geddie Road, Tallahassee, Florida.

Project: The applicant proposes to retire the existing boiler for Steam Generating Unit 2 (EU-004) and re-power the Unit 2 steam turbine-electrical generator by installing a new combined cycle unit. The proposed unit will consist of a new combustion turbine and a new heat recovery steam generator (HRSG) with a gas-fired duct burner. The combustion turbine will produce a nominal 188 MW of direct power and the HRSG will re-power the existing Unit 2 steam-electrical generator to produce another 238 MW. The project will not result in an increase in steam-generated electricity. Therefore, only a modification of the site certification is necessary.

NOx emissions from the new combined cycle unit will be controlled by a selective catalytic reduction (SCR) system when firing either natural gas or distillate oil. The applicant's PSD netting analysis indicates that there will be no PSD-significant emissions increases for the project to re-power Unit 2. The project results in a minor source air construction permit.

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 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 fourteen (14) days from the date of publication of this Public Notice. Written comments must be provided to the Permitting Authority at the above address. Any written comments filed will be made available for public inspection. 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.

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 fourteen (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 fourteen (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

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 fourteen (14) days from the date of publication of this Public Notice. Written comments must be provided to the Permitting Authority at the above address. Any written comments filed will be made available for public inspection. 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.

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 fourteen (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 fourteen (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 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 how and when the petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so 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; 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.

SEPTEMBER 1, 2006

Adams, Patty

From: Vielhauer, Trina
Sent: Friday, September 08, 2006 3:13 PM
To: Adams, Patty; Koerner, Jeff
Subject: FW: Proof of Publication
Attachments: Public Notice of Intent.pdf

From: Jones, Tron [mailto:JonesTr@talgov.com]
Sent: Friday, September 08, 2006 3:11 PM
To: Vielhauer, Trina
Cc: Powell, John
Subject: Proof of Publication

From the Desk of John K. Powell:

<<Public Notice of Intent.pdf>>

"The Improper Use of Knowledge Will Forevermore Lead to Regret"

Memorandum # Florida Department of Environmental Protection

TO: Trina Vielhauer, Chief - Bureau of Air Regulation

FROM: Jeff Koerner, Air Permitting North Program JK

DATE: August 22, 2006

SUBJECT: Draft Air Permit No. 0730003-009-AC
City of Tallahassee, Electric Utilities
Arvah B. Hopkins Generating Station
Unit 2 Re-Powering 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
- PE Certification

The draft permit authorizes construction of a new General Electric 7FA combustion turbine (188 MW) and gas-fired heat recovery steam generator (HRSG) to re-power the existing Hopkins Unit 2 steam turbine-electrical generator set (238 MW). The existing Unit 2 boiler will be permanently shut down as part of this project. The new combined cycle unit includes an SCR system and avoids PSD preconstruction review. The new equipment will be installed at the Arvah B. Hopkins Generating Station, which is located in Leon County at 1125 Geddie Road, Tallahassee, Florida.

The Technical Evaluation and Preliminary Determination provides a detailed description of the project, rule applicability, and emissions standards. The P.E. certification briefly summarizes the proposed project. Day #90 is September 4, 2006. I recommend your approval of the attached Draft Permit for this project.

Attachments

P.E. CERTIFICATION STATEMENT

PERMITTEE

City of Tallahassee, Electric Utilities
Arvah B. Hopkins Generating Station
2602 Jackson Bluff Road
Tallahassee, Florida 32304

Draft Air Permit No. 0730003-009-AC
Arvah B. Hopkins Generating Station
Unit 2 Re-Powering Project
Leon County, Florida

PROJECT DESCRIPTION

The applicant proposes to retire the existing boiler for Steam Generating Unit 2 (EU-004) and re-power the Unit 2 steam turbine-electrical generator by installing a new combined cycle unit. The proposed unit will consist of a new combustion turbine and a new heat recovery steam generator (HRSG) with a gas-fired duct burner. The combustion turbine will produce a nominal 188 MW of direct power and the HRSG will re-power the existing Unit 2 steam-electrical generator to produce another 238 MW. The project will not result in an increase in steam-generated electricity. Therefore, only a modification of the site certification is necessary.

NOx emissions from the new combined cycle unit will be controlled by an SCR system to 5 ppmvd @ 15% oxygen (natural gas) and 10 ppmvd @ 15% oxygen (distillate oil). The applicant's PSD netting analysis indicates that there will be no PSD-significant emissions increases for the project to re-power Unit 2. The project results in a minor source air construction permit.

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

Jeffery J. Koerner 8-22-06

Jeffery F. Koerner, P.E. (Date)
Registration Number: 49441

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

August 25, 2006

Mr. Robert E. McGarrah, Production Superintendent
City of Tallahassee, Electric Utilities
Arvah B. Hopkins Generating Station
2602 Jackson Bluff Road
Tallahassee, Florida 32304

Re: Air Construction Permit No. 0730003-009-AC
Arvah B. Hopkins Generating Station
Unit 2 Re-Powering Project

Dear Mr. McGarrah:

On June 7, 2006, you submitted an application to construct a new 188 MW combustion turbine and gas-fired heat recovery steam generator (HRSG) at the existing Arvah B. Hopkins Generating Station, which is located in Leon County at 1125 Geddie Road, Tallahassee, Florida. The proposed new combined cycle unit will be used to re-power the existing Unit 2 steam turbine-electrical generator set (238 MW). The existing Unit 2 boiler will be permanently shut down. Enclosed are the following documents: "Technical Evaluation and Preliminary Determination", "Draft Permit", "Written Notice of Intent to Issue Air Permit", and "Public Notice of Intent to Issue Air Permit".

The "Technical Evaluation and Preliminary Determination" summarizes the Permitting Authority's technical review of the application and provides the rationale for making the preliminary determination to issue a Draft Permit. The proposed "Draft Permit" includes the specific conditions that regulate the emissions units covered by the proposed project. The "Written Notice of Intent to Issue Air Permit" provides important information regarding: the Permitting Authority's intent to issue an air permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue an air permit; the procedures for submitting comments on the Draft Permit; the process for filing a petition for an administrative hearing; and the availability of mediation. 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, Jeff Koerner, at 850/921-9536.

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

City of Tallahassee, Electric Utilities
Arvah B. Hopkins Generating Station
2602 Jackson Bluff Road
Tallahassee, Florida 32304

Authorized Representative:
Mr. Robert E. McGarrah, Production Superintendent

Air Permit No. 0730003-009-AC
Facility ID No. 0730003
Arvah B. Hopkins Generating Station
Unit 2 Re-Powering Project
Leon County, Florida

Facility Location: The City of Tallahassee operates the existing Arvah B. Hopkins Generating Station, which is located in Leon County at 1125 Geddie Road, Tallahassee, Florida.

Project: The applicant proposes to construct a new 188 MW combustion turbine and gas-fired heat recovery steam generator (HRSG) to re-power the existing Unit 2 steam turbine-electrical generator set (238 MW). The existing Unit 2 boiler will be permanently shut down as part of this project. 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 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 Sections 403.087 and 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 Rule 62-110.106(5), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within seven (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 fourteen (14) days from the date of publication of the Public Notice. Written comments must be provided to the Permitting Authority at the above address. Any written comments filed will be made available for public inspection. 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.

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 fourteen (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 fourteen (14) days of publication of the attached Public Notice or within fourteen (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 fourteen (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 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 how and when each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so 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; 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 certified mail (*) and copies were mailed by U.S. Mail before the close of business on 8/28/06 to the persons listed below.

Mr. Robert E. McGarrah, City of Tallahassee*
Mr. John Powell, City of Tallahassee
Mr. Ken Kosky, Golder Associates Inc.
Ms. Sandra Veazey, NWD Office
Mr. Jim Little, EPA Region 4

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.

(Clerk) 8/28/06 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Draft Air Permit No. 0730003-009-AC
Arvah B. Hopkins Generating Station, Unit 2 Re-Powering Project
Leon County, Florida

Applicant: The applicant for this project is the City of Tallahassee.. The City of Tallahassee's Authorized Representative is Mr. Robert E. McGarrah, Production Superintendent. The City's mailing address is 2602 Jackson Bluff Road, Tallahassee, Florida 32304.

Facility Location: The City of Tallahassee operates the existing Arvah B. Hopkins Generating Station, which is located in Leon County at 1125 Geddie Road, Tallahassee, Florida.

Project: The applicant proposes to retire the existing boiler for Steam Generating Unit 2 (EU-004) and re-power the Unit 2 steam turbine-electrical generator by installing a new combined cycle unit. The proposed unit will consist of a new combustion turbine and a new heat recovery steam generator (HRSG) with a gas-fired duct burner. The combustion turbine will produce a nominal 188 MW of direct power and the HRSG will re-power the existing Unit 2 steam-electrical generator to produce another 238 MW. The project will not result in an increase in steam-generated electricity. Therefore, only a modification of the site certification is necessary.

NOx emissions from the new combined cycle unit will be controlled by a selective catalytic reduction (SCR) system when firing either natural gas or distillate oil. The applicant's PSD netting analysis indicates that there will be no PSD-significant emissions increases for the project to re-power Unit 2. The project results in a minor source air construction permit.

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 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 fourteen (14) days from the date of publication of this Public Notice. Written comments must be provided to the Permitting Authority at the above address. Any written comments filed will be made available for public inspection. 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.

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 fourteen (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 fourteen (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 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 how and when the petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so 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; 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
&
PRELIMINARY DETERMINATION

PROJECT

Draft Air Construction Permit No. 0730003-009-AC
Arvah B. Hopkins Generating Station
Unit 2 Re-Powering Project

COUNTY

Leon County, Florida

APPLICANT

City of Tallahassee
Arvah B. Hopkins Generating Station
2602 Jackson Bluff Road
Tallahassee, Florida 32304

ARMS Facility ID No. 0730003

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Air Permitting North Program

August 22, 2006

{Filename: TEPD - 0730003-009-AC}

1. GENERAL PROJECT INFORMATION

Facility Description and Location

The City of Tallahassee operates the Arvah B. Hopkins Generating Station (ARMS ID No. 0730003). This is an existing power plant (SIC No. 4911) that is located in Leon County at 1125 Geddie Road, Tallahassee, Florida. The plant is bounded by Geddie Road to the west, CSX railroad to the east, State Road 20 to the south and U.S. Highway 90 to the north. The site is in an area that is in attainment with, or designated as unclassifiable for, the Ambient Air Quality Standard (NAAQS). Based on current Title V Air Operation Permit No. 0730003-007-AV, the existing plant consists of the following equipment.

- Steam Generating Unit 1 (EU-001) is a Foster-Wheeler Model No. SF-5 boiler rated at 75 MW. The unit is authorized to fire natural gas or fuel oil. It is subject to the Phase II Acid Rain provisions. The unit began commercial operation in May of 1971.
- Combustion Turbine 1 (EU-002) is a Westinghouse Model No. W191G combustion turbine rated at 16.47 MW. The unit is authorized to fire natural gas or No. 2 oil. It is not subject to NSPS Subpart GG for combustion turbines. The unit began commercial operation in February of 1970.
- Combustion Turbine 2 (EU-003) is a Westinghouse Model No. W251G combustion turbine rated at 26.8 MW. The unit is authorized to fire natural gas or No. 2 oil. It is not subject to NSPS Subpart GG for combustion turbines. The unit began commercial operation in September of 1972.
- Steam Generating Unit 2 (EU-004) is a Babcock & Wilcox Model No. RB-533 boiler rated at 238 MW. The unit is authorized to fire natural gas or fuel oil. It is subject to the Phase II Acid Rain provisions and a Florida Power Plant Site Certification No. PA 74-03D. The unit began commercial operation in October of 1977.
- The facility also includes: fugitive VOC sources (EU-005) such as painting operations; general purpose engines (EU-006); and emergency generators (EU-007).

On May 10, 2004, the Department issued Permit No. 0730003-004-AC, which authorized the temporary installation of 23 portable combustion turbine-generator sets (EU-008 through EU-030) rated at approximately 5.5 MW (each) of output. The purpose of the project was to ensure reliable power during the temporary period that Combined Cycle Unit 8 at the City of Tallahassee's Purdom Plant was being repaired and returned to service. These units had limited service, have been removed from the site, and are no longer authorized to operate.

On October 26, 2004, the Department issued an air construction Permit No. 0730003-005-AC (PSD-FL-343) to add two General Electric LM 6000PC SPRINT simple cycle combustion turbines (EU-031 and EU-032). Each unit has a capacity of approximately 50 MW and fires both natural gas and distillate oil. NOx emissions are controlled by water injection and hot selective catalytic reduction (SCR) systems. The units commenced operation in September of 2005. The Bureau of Air Regulation is processing a pending application to revise the current Title V air operation permit to incorporate these units.

Regulatory Categories

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

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

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

PSD: The facility is a PSD-major facility in accordance with Rule 62-212.400, F.A.C.

NSPS: The facility operates units subject to the New Source Performance Standards in 40 CFR 60.

NEHSAP: The facility operates units subject to National Emissions Standards for HAPs in 40 CFR 63.

Project Description

The applicant proposes to retire the existing boiler for Steam Generating Unit 2 (EU-004) and re-power the Unit 2 steam turbine-electrical generator by installing a new combined cycle unit. The proposed unit will consist of a new combustion turbine and a new heat recovery steam generator (HRSG) with a gas-fired duct burner. The combustion turbine will produce a nominal 188 MW of direct power and the HRSG will re-power the existing Unit 2 steam-electrical generator to produce another 238 MW. The project will not result in an increase in steam-generated electricity. Therefore, only a modification of the site certification is necessary. The applicant provided a PSD netting analysis to show that there will be no PSD-significant emissions increases for the project to re-power Unit 2.

Combustion Turbine: The proposed combustion turbine is a new General Electric Model No. PG7241(FA) with DLN 2.6 combustors and a Mark VI automated control system (or equivalent). The combustion turbine will be capable of firing natural gas and distillate oil ($\leq$ 0.05% sulfur by weight). Based on the higher heating value of each fuel and a compressor inlet temperature of 25° F, the design maximum heat input rates are 1899 MMBtu per hour for gas firing and 2079 MMBtu per hour for oil firing. Nitrogen oxide emissions will be controlled by a selective catalytic reduction (SCR) system plus the dry low-NOx (DLN) combustion system when firing natural gas and water injection when firing distillate oil. Emissions of carbon monoxide and volatile organic compounds will be minimized by the firing of clean fuels and efficient combustion at the high temperatures in the unit. Emissions of particulate matter will be minimized by the large inlet air filtration system, the firing of clean fuels, and the efficient combustion at high temperatures in the unit. Emissions of sulfuric acid mist and sulfur dioxide will be minimized by the firing of natural gas as the primary fuel and the firing of distillate oil ($\leq$ 0.05% sulfur by weight) as a restricted alternate fuel.

DLN Combustion: The applicant will operate and maintain the General Electric dry low-NOx DLN 2.6 combustion system (or better) to control NOx emissions from the combustion turbine when firing natural gas. Prior to the initial emissions performance tests required for the combustion turbine, the DLN combustors and automated combustion turbine control system will be tuned to achieve the permitted CO and NOx levels for simple cycle operation. Thereafter, the system will be maintained and tuned in accordance with the manufacturer's recommendations.

Water Injection Technology: The applicant will install, operate, and maintain a water injection system to reduce NOx emissions when firing distillate oil. Prior to the initial emissions performance tests, the water injection system will be tuned to achieve the permitted NOx levels. Thereafter, the system will be maintained and tuned in accordance with the manufacturer's recommendations.

SCR System: The applicant will install, operate, and maintain a selective catalytic reduction (SCR) system to control NOx emissions from the combustion turbine when firing either natural gas or distillate oil during combined cycle operation (including periods when steam is dumped to a condenser). The SCR system will consist of an ammonia injection grid, catalyst modules, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system will be designed, constructed and operated to achieve the permitted levels for NOx emissions. The designed maximum ammonia slip level is 5 ppmvd @ 15% oxygen. In accordance with 40 CFR 60.130, the storage of ammonia will comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

Heat Recovery Steam Generator (HRSG) and Exhaust Stacks: The new combustion turbine will be paired with a new HRSG to recover heat from the combustion turbine exhaust and generate steam to re-power the existing Unit 2 steam-electrical generator. The HRSG will be equipped with a gas-fired duct burner system designed for a maximum heat input rate of 765 MMBtu per hour. When firing natural gas and duct firing, exhaust gas at 188° F will leave the HRSG and exit a stack that is 18 feet in diameter and 150 feet tall with a volumetric flow rate of approximately 1,016,100 acfm. When firing distillate oil and duct firing, exhaust gas at 204° F will leave the HRSG and exit a stack that is 18 feet in diameter and 150 feet tall with a volumetric flow rate of approximately 1,090,210 acfm. When operating in simple cycle mode with the blanking plate installed, exhaust gas at 1114° F will exit an emergency bypass stack that is also 18 feet in diameter and 150 feet tall with a volumetric flow rate of approximately 2,433,700 acfm. Temperatures and gas flows assume a compressor inlet temperature of 59° F.

Fuel Storage: The existing plant includes: two 10,000 bbl (barrel) diesel storage tanks: one 55,000 bbl (barrel) No. 6 oil storage tank; and one 180,000 bbl No. 6 oil storage tank. As part of the project, the 180,000 bbl tank will be converted to store diesel (distillate oil). The converted tank and the two existing diesel tanks will supply the new combined cycle combustion turbine. No new tanks will be installed.

Methods of Operation: The proposed combustion turbine will operate as a combined cycle unit to include the following primary methods of operation: gas firing; gas firing with duct firing; oil firing; and oil firing with duct firing. The proposed combustion turbine may also operate as a combined cycle unit with the HRSG and SCR in operation, but steam being dumped to a condenser. This would occur if there were problems with the existing steam-electrical generator. Whenever operated as a combined cycle unit, the SCR will be functioning.

During normal combined cycle operation, a blanking plate ensures a good seal such that exhaust will not bypass the HRSG stack. However, if there are problems with the HRSG, SCR, or steam-electrical generator, the blanking plate will be moved to redirect exhaust gases through the HRSG bypass stack. For this case, the SCR system is not functional and no steam is produced because the HRSG is being bypassed. Although the reconfiguration might take several days, it would allow operation as a simple cycle unit and some direct electrical generation while the other systems are being repaired. Whenever operating in the simple cycle HRSG/SCR bypass mode, only natural gas will be fired.

Processing Schedule

On June 7, 2006, the Department received the application for a minor source air pollution construction permit to avoid PSD preconstruction review, which included a PSD netting analysis. The application was deemed complete upon receipt. However, on August 17, 2006, the applicant did provide additional details by emails regarding various startup modes for the combustion turbine.

2. APPLICABLE REGULATIONS

State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations defined in the following Chapters of the Florida Administrative Code: 62-4 (Permitting Requirements); 62-204 (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Preconstruction Review, PSD Review and BACT, and Non-Attainment Area Review and LAER); 62-213 (Title V Air Operation Permits for Major Sources of Air Pollution); 62-296 (Emission Limiting Standards); and 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 EPA in the following sections of the Code of Federal Regulations (CFR). These regulations are adopted in Rule 62-204.800, F.A.C.

40 CFR 60 - New Source Performance Standards (NSPS)

Subpart KKKK: On July 6, 2006, EPA published the final NSPS Subpart KKKK provisions for combustion turbines in the Federal Register. Subpart KKKK supersedes the requirements of NSPS Subparts GG for combustion turbines and Da for duct burners. The new regulation imposes NOx and SO_2 emissions standards for units that are constructed, modified, or reconstructed after February 18, 2005. The combustion turbine proposed for this project would be considered a new unit with a maximum heat input rate (HHV) greater than 850 MMBtu per hour. As such Subpart KKKK establishes the following standards:

- NOx ≤ 15 ppmvd at 15% O_2 (0.43 lb/MWh) for gas firing;
- NOx ≤ 42 ppmvd at 15% O_2 (1.3 lb/MWh) for oil firing; and
- SO_2 ≤ 0.060 lb SO_2/MMBtu for all fuels.

The applicant proposes the following NOx standards for the new combustion turbine: 5 ppmvd @ 15% oxygen when firing natural gas in combined cycle operation; 9 ppmvd @ 15% oxygen when firing natural gas in simple cycle operation; and 10 ppmvd @ 15% oxygen when firing distillate oil in combined cycle operation. The applicant also proposes to fire only natural gas and distillate oil with a maximum sulfur content of 0.05% by weight. This is equivalent to approximately 0.055 lb SO_2/MMBtu for natural gas (assuming a maximum tariff specification of 20 grains of sulfur per 100 scf) and 0.05 lb SO_2/MMBtu for the proposed distillate oil. The new combustion turbine will readily comply with the NSPS provisions for NOx and SO_2. Units subject to any NSPS Subpart are also subject to the applicable requirements of Subpart A (General Provisions).

40 CFR 63 - National Emissions Standards for Hazardous Air Pollutants for Source Categories (NESHAP)

Subpart YYYY: This subpart establishes a formaldehyde standard of 91 ppbv corrected to 15% oxygen for new combustion turbines. Currently, units subject to the formaldehyde standard are required to conduct initial and annual tests to demonstrate compliance. Units subject to any NESHAP Subpart are also subject to Subpart A (General Provisions) and any applicable Appendices. However, on August 18, 2004, EPA stayed the effectiveness of NESHAP Subpart YYYY for lean premix and diffusion flame combustion turbines.

PSD Applicability - General

The Department regulates major air pollution facilities in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rules 62-212.400(PSD) and 62-210.200(Definitions), 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. A facility is considered "major" with respect to PSD if it emits or has the potential to emit: 250 tons per year or more of any regulated air pollutant, or 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 PSD Major Facility Categories, or 5 tons per year of lead.

For projects at PSD-major facilities, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates defined in Rule 62-210.200, 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 subject to PSD preconstruction review for several PSD-significant pollutants and required to install BACT controls for these pollutants.

PSD Applicability - Project

The existing facility is a fossil fuel-fired steam electric plant with a maximum heat input rate of more than 250 MMBtu per hour, which is one of the 28 PSD Major Facility Categories. Actual and potential emissions of several pollutants are greater than the 100 tons per year threshold, which makes the existing plant a PSD-major facility. The applicant proposes to modify existing Unit 2 by shutting down the boiler and re-powering the steam turbine-electrical generator with steam generated from a new heat recovery steam generator as part of a new combined cycle combustion turbine system. The applicant estimates the following emissions changes as a result of the modification.

Pollutant	Existing Unit 2 Baseline Emissions, TPY	Re-Powered Unit 2 Potential Emissions, TPY	Net Increase TPY	PSD SER TPY	PSD?
SO_2	1642.0	211.7	-1,430	40	No
PM	136.3	111.9	-24	25	No
PM_{10}	97.5	111.9	14	15	No
NOx	843.3	332.1	-511	40	No
CO	241.1	340.1	99	100	No
VOC	19.7	47.4	28	40	No
SAM	73.0	39.8	-33	7	No
Lead	38 lb	100 lb	62 lb	1200 lb	No
Mercury	Negligible	Negligible	Negligible	200 lb	No

For the above analysis, the applicant estimated baseline actual annual emissions from existing Unit 2 based on the following.

- For CO, PM, PM_{10}, VOC, lead, and mercury, annual emissions were based on emissions factors and operational data for the highest consecutive 24-month period between 2001 and 2005.
- For NOx, annual emissions were based on CEMS data for the highest consecutive 24-month period collected from March 2003 to April 2005.
- For SO_2, annual emissions were based on continuous fuel oil sulfur sampling and analysis data for the highest consecutive 24-month period from February 2004 to January 2006.

For the above analysis, the applicant estimated future potential annual emissions from the re-powered Unit 2 based on the following.

- Potential annual emissions are based on: the proposed emissions standards and/or vendor data; the operational restrictions; a maximum heat input rate from firing natural gas of 1795 MMBtu per hour at compressor inlet temperature of 59° F; and a maximum heat input rate from firing distillate oil of 1979 MMBtu per hour at compressor inlet temperature of 59° F.
- The maximum annual distillate oil firing rate is 6,926,500 MMBtu (HHV), which is equivalent to 3500 hours per year of full load operation.
- The maximum annual duct firing rate is 2,598,800 MMBtu per year (HHV), which is equivalent to 3650 hours per year at the maximum duct firing rate.

- Normal gas firing was used for the remainder of the annual operation, except for NOx. For NOx, simple cycle HRSG/SCR bypass stack operation while firing natural gas was used for the remainder of the annual operation. NOx emissions in this mode were estimated without control by the SCR system.

3. DEPARTMENT REVIEW

New Combined Cycle Combustion Turbine Unit - Discussion of Emissions and Limitations

For the new equipment, the permitted capacities will be:

- Based on the higher heating value of each fuel and a compressor inlet temperature of 25° F, the design maximum heat input rates for the combustion turbine are 1899 MMBtu per hour for gas firing and 2079 MMBtu per hour for oil firing.
- The maximum heat input rate for the HRSG Duct Burner is 765 MMBtu per hour.

As previously described, the project avoids PSD preconstruction review. However, the PSD netting analysis was contingent on the following assumptions, which will be included in the draft permit as limitations.

- Prior to commencing commercial operation of the new combined cycle combustion turbine, the applicant will permanently shutdown and render incapable of operation the existing Unit 2 boiler.
- The maximum distillate oil firing rate will be 6,926,500 MMBtu (HHV) per year of heat input to the combustion turbine, which is equivalent to 3500 hours per year of full load operation.
- The maximum duct firing rate will be 2,598,800 MMBtu (HHV) per year, which is equivalent to 3650 hours per year at the maximum duct firing rate.
- The combustion turbine shall fire only natural gas with no duct firing when operating as a simple cycle unit with the exhaust bypassing the HRSG and SCR system. To operate in this manner, the unit must be cooled and a blanking plate installed to direct exhaust gases to the bypass stack. This method of operation will be an infrequent occurrence, most likely due to problems or maintenance of the HRSG, SCR system or steam turbine-electrical generator system.

Based on the application and vendor information, the combustion turbine will be subject to the following emissions standards:

Pollutant	Fuel	Operating Method [a]	Emission Standard		Averaging Period	Compliance Method
			ppmvd @ 15% O_2	Equivalent lb/hour [b]		
CO [c]	Gas	Combined Cycle	16.8	96.8	30-day rolling avg.	CO CEMS
		SC/Bypass	10.0	41.7	4-hour test avg.	EPA Method 10
	Oil	Combined Cycle	21.4	142.9	30-day rolling avg.	CO CEMS
	All Fuels	All methods	340.10 tons		12-month rolling total	CO CEMS
NOx [d]	Gas	Combined Cycle	5.0	47.8	30-day rolling avg. [c]	NOx CEMS
		SC/Bypass	9.0	61.8	4-hour test avg.	EPA Method 7E
	Oil	Combined Cycle	10.0	108.4	30-day rolling avg. [c]	NOx CEMS
Opacity	All Fuels	All Methods	10 % Opacity		6-minute block avg.	EPA Method 9

a. "SC/Bypass" means operation as a simple cycle unit with the blanking plate installed to bypass the HRSG and SCR system and exhaust directly to the bypass stack.

b. Mass emissions rates represent the maximum equivalent "lb/hour" for the highest emitting method of operation, which includes duct firing for most cases. Mass emissions rates are based on a compressor inlet temperature of 25° F and the higher heating value of each fuel. Maximum mass emission rates will vary based on the actual test conditions in accordance with the performance curves and/or equations. For the combustion turbine, it is not necessary to continuously report hourly mass emissions rates with the CEMS data. See Appendix F for a summary of equivalent mass emissions rates.

c. To determine compliance with the emissions standards based on a 30-day rolling average, each fuel will have a separate 30-day rolling emissions standard based on CEMS data. To determine compliance with the CO emissions cap based on a 12-month rolling total, the mass emissions rate shall be determined from all valid hourly emissions data including periods such as startup, shutdown, malfunction, fuel switching, and tuning. Mass emissions may be determined from the CEMS data by using the appropriate F-Factor for each fuel.

d. To determine compliance with the NOx emissions standards based on a 30-day rolling average, each fuel will have a separate 30-day rolling emissions standard based on NOx CEMS data.

{Permitting Note: Potential annual emissions from the combustion turbine system are: 340 tons/year of CO, 332 tons/year of NOx, 112 tons/year of PM/PM$_{10}$, 212 tons/year of SO_2, 40 tons/year of SAM, and 47 tons/year of VOC. Note that the project requires the shutdown of the existing Unit 2 boiler, which provided emissions decreases and allowed the project to avoid PSD preconstruction review. Potential annual emissions are based on: the permitted emissions standards; the operational restrictions in the permit; a maximum heat input rate from firing natural gas of 1795 MMBtu per hour at compressor inlet temperature of 59° F; and a maximum heat input rate from firing distillate oil of 1979 MMBtu per hour at compressor inlet temperature of 59° F.}

Ammonia Slip

The SCR system will be designed to achieve a maximum ammonia slip of 5 ppmvd @ 15% oxygen. The draft permit specifies that actual ammonia slip levels shall not exceed 10 ppmvd @ 15% oxygen as determined by EPA Method CTM-027 based on the average of three test runs. If tests indicate an ammonia slip level greater than 5 ppmvd @ 15% oxygen, the permittee shall:

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

b. Before the ammonia slip exceeds 10 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is less than 5 ppmvd corrected to 15% oxygen within 45 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis.

Ammonia Injection Monitoring

To accommodate NOx monitor down times and malfunctions, the draft permit also requires installation, calibration, operation and maintenance of an ammonia flow meter to measure and record the ammonia injection rate to the SCR system in accordance with the manufacturer's specifications. The general range of ammonia flow rates required to meet permitted emissions levels shall be documented over the range of load conditions allowed by this permit by comparing NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, ammonia shall be injected at a rate that is consistent with the documented flow rate for the combustion turbine load conditions. [Rules 62-4.070(3), F.A.C.]

Excess Emissions Requirements

For this project, the steam turbine generator is quite large and nearly 30 years old. As such, it requires a careful warm up and heat soak to prevent metal fatigue. To accomplish this, the combustion turbine must operate at low load levels to gradually warm up the steam turbine generator in addition to the HRSG and SCR system. At these low loads, the combustion turbine is not yet in full lean premix combustion and CO and NOx emissions may be elevated beyond the control of the operator.

In addition to startup, the DLN combustion system and water injection system must be periodically tuned to ensure proper operation and low emission levels. During tuning, the combustion turbine is stepped through low load levels and SCR system will be shut down to gather emissions data. In addition, it may be necessary to gather this data to tune the SCR system. Again, operation at low load levels means that CO and NOx emissions may be elevated beyond the control of the operator.

During an oil-to-gas fuel switch, the combustion turbine is ramped down to low load levels on oil, the water injection system is shut down, oil firing is reduced while gas firing is initiated and taken through the dry low-NOx combustion process to full lean premix. During a gas-to-oil fuel switch, the combustion turbine is typically ramped down, water injection initiates, and oil is blended in while gas is gradually reduced and shut off. Fuel switching may cause excess CO and NOx levels beyond the control of the operator.

In accordance with Rule 62-210.700(5), F.A.C., the draft permit allows limited periods of excess emissions due to these defined events as follows.

As specified in this condition, excess emissions resulting from startup, shutdown, malfunction, fuel switches, and DLN/SCR/WI tuning are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such events. For excess emissions events that last less than the maximum duration allowed, only those minutes attributable to excess emissions from the event shall be excluded. When authorized, excess emissions data shall be excluded from a compliance determination as a continuous block attributed to the event.

a. *Startup*:

   1) Steam Turbine Generator Cold Startup: No more than the first 600 minutes of CEMS data shall be excluded due to excess emissions from a steam turbine generator cold startup. A "steam turbine generator cold startup" is defined as startup after the steam turbine generator has been offline for 24 hours or more, or the first stage turbine metal temperature is 250°F or less.

   2) Steam Turbine Generator Warm Startup: No more than the first 300 minutes of CEMS data shall be excluded due to excess emissions from a steam turbine generator warm startup. A "steam turbine generator warm startup" is defined as startup to combined cycle operation when the gas turbine has been shut down for a period of time and the first stage steam turbine metal temperature is greater than 250°F.

   3) Steam Turbine Generator Hot Startup: No more than the first 240 minutes of CEMS data shall be excluded due to excess emissions from a steam turbine generator hot startup. A "steam turbine generator hot startup" is defined as startup of the steam turbine generator while the unit has been operating in the combined cycle mode with the steam being dumped to the condenser.

   4) Simple Cycle HRSG/SCR Bypass Startup: No more than the first 30 minutes of CEMS data shall be excluded due to excess emissions from a simple cycle gas turbine startup in which exhaust is directed to the HRSG/SCR bypass stack.

b. *Shutdown*: No more than the first 30 minutes of CEMS data shall be excluded due to excess emissions from a combustion turbine shutdown. For shutdowns of less than 30 minutes in duration, only those minutes attributable to excess emissions from shutdown shall be excluded.

c. *Malfunction*: No more than 120 minutes of CEMS data shall be excluded in a 24-hour period due to excess emissions from malfunction. 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.

d. *Fuel Switch*: No more than the first 30 minutes of CEMS data shall be excluded due to excess emissions from a fuel switch. For fuel switches less than 30 minutes in duration, only those minutes attributable to excess emissions from fuel switching shall be excluded.

e. *DLN/SCR/WI Tuning*: No more than 72 hours of CEMS data during any consecutive 12 months shall be excluded from the CEMS compliance demonstration due to excess emissions from the necessary tuning of the dry low-NOx (DLN) combustion system, the selective catalytic reduction (SCR) system, or the water injection (WI) system. Tuning sessions shall be performed in accordance with the manufacturer's recommendations or industry standards. Prior to performing any DLN, SCR, or WI tuning session, the permittee shall provide the Compliance Authority with an advance notice (telephone, facsimile transmittal, or electronic mail) that details the activity and proposed tuning schedule. *{Permitting Note: DLN tuning sessions are typically required after completion of initial construction, a combustor change-out, a major repair, a unit overhaul, maintenance to a combustor, or other similar circumstances. During DLN or water injection tuning, the SCR system is turned off and the combustion turbine is sequentially stepped through numerous loads (including low load levels) to gather actual emissions data and operational information for use in adjusting the combustion turbine and control system.}*

As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for the specifically defined periods. Data exclusion does not apply to the CO emissions cap based on a 12-month rolling total.

The draft permit also includes the following alternate visible emissions standard to address opacity during startup: "Visible emissions due to startup shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity." In addition, the draft permit requires a report for the first year of startups and allows the Department to lower the durations based on the actual information for this unit.

HRSG/SCR Bypass Simple Cycle Operation

Because the bypass stack will only be used in emergency situations where the HRSG, SCR and/or steam turbine-generator are unavailable, the permittee is not required to install CO/NOx CEMS or permanent test ports on the bypass stack. When an emergency situation occurs, the permittee shall ensure that the unit is firing only natural gas and is properly operating with lean premix combustion (Mode 6). The permittee shall monitor the hours of operation in simple cycle HRSG/SCR bypass mode and use the following methods to determine CO and NOx emissions.

a. Compliance with the NOx and CO emission standards for the simple cycle HRSG/SCR bypass mode of operation shall be demonstrated by conducting initial and annual tests as required by this permit.

b. Compliance with the 12-month rolling CO emissions cap, the maximum CO mass emission rate of 41.7 lb/hour shall be used to represent each hour of operation in this mode.

If the unit operates in simple cycle mode for a substantial period of time, the Compliance Authority may request additional CO and NOx testing to demonstrate compliance with the standards. The above sampling method is similar to the method allowed under the Acid Rain program for bypass stack situations as described in 40 CFR 75.17(d)(2).

Records and Reports

In addition to the continuous monitoring data collected, the draft permit requires the plant to maintain records of the operating rates, fuel firing rates, and distillate oil fuel sulfur content. The draft permit also requires submittal of the following reports: stack test reports, CEMS RATA reports, Excess Emissions Reports, and an Annual Operating Report. Because compliance with the CO and NOx standard is based on 30-day rolling averages, the draft permit requires the applicant to submit a report summarizing the CO and NOx emissions as determined by data collected from the required CEMS for the initial 60 operating days within 15 calendar days of completing the initial 60 operating days.

4. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete 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. Jeff Koerner 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

City of Tallahassee, Electric Utilities
Arvah B. Hopkins Generating Station
2602 Jackson Bluff Road
Tallahassee, Florida 32304

Authorized Representative:
Mr. Robert E. McGarrah, Production Superintendent

Air Permit No. 0730003-009-AC
Arvah B. Hopkins Generating Station
Facility ID No. 0730003
SIC No. 4911
Unit 2 Re-Powering Project
Permit Expires: July 1, 2009

PROJECT AND LOCATION

This permit authorizes the construction of a General Electric 7FA combustion turbine (188 MW) and gas-fired heat recovery steam generator (HRSG) to re-power the existing Unit 2 steam turbine-electrical generator set (238 MW). The existing Unit 2 boiler will be permanently shut down as part of this project. The new equipment will be installed at the Arvah B. Hopkins Generating Station, which is located in Leon County at 1125 Geddie Road, Tallahassee, Florida.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Parts 60 and 63 of the Code of Federal Regulations. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

(DRAFT)

Joe Kahn, P.E., Acting Director
Division of Air Resource Management

(Date)

FACILITY AND PROJECT DESCRIPTION

The City of Tallahassee operates the Arvah B. Hopkins Generating Station, which is an existing power plant (SIC No. 4911). The plant currently consists of:

- Steam Generating Unit 1 (EU-001) is a Foster-Wheeler Corporation Model No. SF-5 boiler rated at 75 MW. The unit is authorized to fire natural gas or fuel oil. It is subject to the Phase II Acid Rain provisions. The unit began commercial operation in May of 1971.
- Combustion Turbine 1 (EU-002) is a Westinghouse Model No. W191G combustion turbine rated at 16.47 MW. The unit is authorized to fire natural gas or No. 2 oil. It is not subject to NSPS Subpart GG for combustion turbines. The unit began commercial operation in February of 1970.
- Combustion Turbine 2 (EU-003) is a Westinghouse Model No. W251G combustion turbine rated at 26.8 MW. The unit is authorized to fire natural gas or No. 2 oil. It is not subject to NSPS Subpart GG for combustion turbines. The unit began commercial operation in September of 1972.
- Steam Generating Unit 2 (EU-004) is a Babcock & Wilcox Model No. RB-533 boiler rated at 238 MW. The unit is authorized to fire natural gas or fuel oil. It is subject to the Phase II Acid Rain provisions and a Florida Power Plant Site Certification No. PA 74-03D. The unit began commercial operation in October of 1977.
- The facility also includes: fugitive VOC sources (EU-005) such as painting operations; general purpose engines (EU-006); and emergency generators (EU-007).
- LM 6000PC SPRINT simple cycle combustion turbines (EU-031 and EU-032). Each unit has a capacity of approximately 50 MW and fires both natural gas and distillate oil. NOx emissions are controlled by water injection and a hot selective catalytic reduction (SCR) system.

{Permitting Note: On May 10, 2004, the Department issued Permit No. 0730003-004-AC, which authorized the temporary installation of 23 portable combustion turbine-generator sets (EU-008 through EU-030) rated at approximately 5.5 MW (each) of output. The purpose of the project was to ensure reliable power during the temporary period that Combined Cycle Unit 8 at the City of Tallahassee's Purdom Plant was being repaired and returned to service. These units have been removed from the site and are no longer authorized to operate.}

This permit authorizes shutdown of the Unit 2 boiler and the re-powering of the Unit 2 steam turbine-electrical generator by installing the following equipment.

ID	Emission Unit Description
033	General Electric 7FA Combined Cycle Combustion Turbine to re-power Unit 2

Due to the shutdown of the Unit 2 boiler, the project avoids PSD preconstruction review for all pollutants.

REGULATORY CLASSIFICATION

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

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

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

PSD: The facility is a PSD-major facility in accordance with Rule 62-212.400, F.A.C.

NSPS: The facility will operate units subject to New Source Performance Standards in 40 CFR 60.

NEHSAP: The facility will operate units subject to National Emissions Standards for HAPs in 40 CFR 63.

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

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's Northwest District Office at 160 Governmental Center, Suite 308, Pensacola, Florida 32502-5794.

3. Appendices: The following Appendices are attached as part of this permit: Appendix A (Citation Format); Appendix B (General Conditions); and Appendix C (Common Conditions); Appendix D (NSPS Subpart KKKK Provisions - Combustion Turbines and Duct Burners); Appendix E (NESHAP Subpart YYYY Provisions – Combustion Turbines); and Appendix F (Emissions Summary).

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

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

6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

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

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

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

10. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(3), F.A.C.]

This section of the permit addresses the following emissions unit.

Emissions Unit No. 033 - General Electric 7FA Combined Cycle Unit
The unit consists of a General Electric 7FA combustion turbine, automated combustion turbine control system, a heat recovery steam generator (HRSG), a gas-fired duct burner system, a HRSG stack, a bypass stack, and CO and NOx CEMS. The combustion turbine will produce a nominal 188 MW and the HRSG will be used to re-power the existing Unit 2 steam turbine-electrical generator to produce a nominal 238 MW. In the combustion turbine, natural gas will be fired as the primary fuel and distillate oil will be fired as a restricted alternative fuel from on site storage tanks. Based on the higher heating value of each fuel and a compressor inlet temperature of 25° F, the design maximum heat input rates are 1899 MMBtu per hour for gas firing and 2079 MMBtu per hour for oil firing. Natural gas will be the sole fuel for the duct burner system rated at a maximum heat input rate of 765 MMBtu per hour.
Nitrogen oxide emissions will be controlled by a selective catalytic reduction (SCR) system plus the dry low-NOx (DLN) combustion system when firing natural gas and water injection when firing distillate oil. Emissions of carbon monoxide and volatile organic compounds will be minimized by the firing of clean fuels and the high combustion temperatures of the combustion turbine. Emissions of particulate matter will be minimized by the large inlet air filtration system and the efficient combustion of the proposed fuels. Emissions of sulfuric acid mist and sulfur dioxide will be minimized by the firing of natural gas as the primary fuel and the restricted firing of distillate oil (≤ 0.05% sulfur by weight) as a backup fuel.
When firing natural gas and duct firing, exhaust gas at 188° F will leave the HRSG and exit a stack that is 18 feet in diameter and 150 feet tall with a volumetric flow rate of approximately 1,016,100 acfm. When firing distillate oil and duct firing, exhaust gas at 204° F will leave the HRSG and exit a stack that is 18 feet in diameter and 150 feet tall with a volumetric flow rate of approximately 1,090,210 acfm. When operating in simple cycle mode with the blanking plate installed, exhaust gas at 1114° F will exit an emergency bypass stack that is also 18 feet in diameter and 150 feet tall with a volumetric flow rate of approximately 2,433,700 acfm. Temperatures and gas flows assume a compressor inlet temperature of 59° F.

EQUIPMENT

1. Unit 2 Boiler – Shutdown: Prior to commencing commercial operation of the new combined cycle combustion turbine, the permittee shall permanently shutdown and render incapable of operation the existing Unit 2 boiler. [Application No. 0730003-009-AC; Rule 62-212.400(12), F.A.C.]

2. New Combined Cycle Unit:

   a. *Combustion Turbine*: The permittee is authorized to install, tune, operate, and maintain the following equipment: a General Electric 7FA combustion turbine-electrical generator set (Model 7241 or equivalent); an inlet air filtration system; an automated combustion turbine control system (Mark VI or equivalent), a heat recovery steam generator (HRSG); a gas-fired duct burner system; a HRSG stack; a bypass stack; and CO and NOx CEMS. The combustion turbine will produce a nominal 188 MW when firing natural gas with a heat input rate of 1899 MMBtu per hour.

   b. *HRSG*: The permittee is authorized to install, operate, and maintain a new heat recovery steam generator (HRSG) designed to recover heat energy from the combustion turbine and deliver steam to the existing Unit 2 steam turbine-electrical generator set. The HRSG will be equipped with supplemental gas-fired duct burner system having a maximum heat input rate of 765 MMBtu per hour (HHV).

   [Application No. 0730003-009-AC; Design]

3. Fuel Tanks: The existing plant includes two 10,000 bbl diesel storage tanks, a 55,000 bbl No. 6 oil storage tank, and a 180,000 bbl No. 6 oil storage tank. As part of the project, the permittee is authorized to convert the 180,000 bbl No. 6 oil storage tank to store diesel (distillate oil). The converted tank and the two existing diesel tanks will supply the new combined cycle combustion turbine. [Application No. 0730003-009-AC]

AIR POLLUTION CONTROL SYSTEMS

4. DLN Combustion: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or

better) to control NO_X emissions from the combustion turbine when firing natural gas. Prior to the initial emissions performance tests required for the combustion turbine, the DLN combustors and automated combustion turbine control system shall be tuned without the SCR in operation to achieve the permitted CO and NOx levels for simple cycle HRSG/SCR bypass operation. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards. [Application No. 0730003-009-AC; Design]

5. Water Injection Technology: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions when firing distillate oil. Prior to the initial emissions performance tests, the water injection system shall be tuned without the SCR in operation to achieve a target NOx level of 42 ppmvd @ 15% oxygen, which represents the vendor's specification for oil firing. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards. [Application No. 0730003-009-AC; Design]

6. SCR System: The permittee shall install, operate, and maintain a selective catalytic reduction (SCR) system to control NOx emissions from the combustion turbine when firing either natural gas or distillate oil during combined cycle operation (including periods when steam is dumped to a condenser). The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions. The SCR system shall be designed to achieve an ammonia slip level of 5 ppmvd @ 15% oxygen. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}*

7. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. The SCR system is not required to be in operation when the unit is operating in simple cycle HRSG/SCR bypass mode. [Rule 62-210.650, F.A.C.]

PERFORMANCE RESTRICTIONS

8. Authorized Fuels: The combustion turbine shall fire only natural gas and distillate oil. The maximum sulfur content of distillate oil shall not exceed 0.05% by weight. The duct burner system shall fire only natural gas. [Application No. 0730003-009-AC; Rule 62-210.200(PTE), F.A.C.]

9. Permitted Capacities:

   a. *Combustion Turbine*: The design maximum heat input rates are 1899 MMBtu per hour for gas firing and 2079 MMBtu per hour for oil firing based on the higher heating value of each fuel, a compressor inlet temperature of 25° F, and full load operation. Heat input rates will vary depending upon combustion turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

   b. *Duct Burner*: The design maximum heat input rate to the duct burner system is 765 MMBtu per hour.

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

10. Restricted Operation:

    a. The hours of operation of the combustion turbine are not limited (8760 hours per year).

    b. Distillate oil firing in the combustion turbine shall not exceed 6,926,500 MMBtu during any consecutive 12 months (equivalent to 3500 hours of full load oil firing).

    c. The duct burner shall fire no more than 2,598,800 MMBtu of natural gas during any consecutive 12 months (equivalent to 3650 hours of full load duct firing).

    [Application No. 0730003-009-AC; Rule 62-210.200(PTE), F.A.C.]

11. Authorized Methods of Operation:

    a. *Combined Cycle Operation*: When operating as a combined cycle unit, the combustion turbine is authorized to fire natural gas or distillate oil and operate the gas-fired duct burners. For this permit, "combined cycle" shall mean operation of the combustion turbine during which heat is recovered from the combustion turbine exhaust in the HRSG to generate steam. This includes operation when the HRSG and SCR system are functioning, but the steam produced is dumped to a condenser.

b. *Simple Cycle HRSG/SCR Bypass Operation*: The combustion turbine shall fire only natural gas with no duct firing when operating as a simple cycle unit with the exhaust bypassing the HRSG and SCR system. To operate in this manner, the unit must be cooled and a blanking plate installed to direct exhaust gases to the bypass stack. This method of operation will be an infrequent occurrence, most likely due to problems or maintenance of the HRSG, SCR system or steam turbine-electrical generator system.

[Application No. 0730003-009-AC]

EMISSIONS STANDARDS

12. Emissions Standards: Emissions from the combined cycle unit shall not exceed the following standards.

Pollutant	Fuel	Operating Method [a]	Emission Standard ppmvd @ 15% O_2	Equivalent lb/hour [b]	Averaging Period	Compliance Method
CO [c]	Gas	Combined Cycle	16.8	96.8	30-day rolling avg.	CO CEMS
		SC/Bypass	10.0	41.7	4-hour test avg.	EPA Method 10 [e]
	Oil	Combined Cycle	21.4	142.9	30-day rolling avg.	CO CEMS
	All Fuels	All methods	340.10 tons	---	12-month rolling total	CO CEMS
NOx [d]	Gas	Combined Cycle	5.0	47.8	30-day rolling avg. [c]	NOx CEMS
		SC/Bypass	9.0	61.8	4-hour test avg.	EPA Method 7E [e]
	Oil	Combined Cycle	10.0	108.4	30-day rolling avg. [c]	NOx CEMS
Opacity	All Fuels	All Methods	10 % Opacity		6-minute block avg.	EPA Method 9

a. "SC/Bypass" means operation as a simple cycle unit with the blanking plate installed to bypass the HRSG and SCR system and exhaust directly to the bypass stack.

b. Mass emissions rates represent the maximum equivalent "lb/hour" for the highest emitting method of operation, which includes duct firing for most cases. Mass emissions rates are based on a compressor inlet temperature of 25° F and the higher heating value of each fuel. Maximum mass emission rates will vary based on the actual test conditions in accordance with the performance curves and/or equations. For the combustion turbine, it is not necessary to continuously report hourly mass emissions rates with the CEMS data. See Appendix F for a summary of equivalent mass emissions rates.

c. To determine compliance with the emissions standards based on a 30-day rolling average, each fuel will have a separate 30-day rolling emissions standard based on CEMS data. To determine compliance with the CO emissions cap based on a 12-month rolling total, the mass emissions rate shall be determined from all valid hourly emissions data including periods such as startup, shutdown, malfunction, fuel switching, and tuning. Mass emissions may be determined from the CEMS data by using the appropriate F-Factor for each fuel.

d. To determine compliance with the NOx emissions standards based on a 30-day rolling average, each fuel will have a separate 30-day rolling emissions standard based on NOx CEMS data.

e. In addition to the methods specified above, data gathered by the CO CEMS and NOx CEMS may be used to demonstrate compliance in accordance with Conditions 26 and 27 in this section.

{Permitting Note: Potential annual emissions from the combustion turbine system are: 340 tons/year of CO, 332 tons/year of NOx, 112 tons/year of PM/PM_{10}, 212 tons/year of SO_2, 40 tons/year of SAM, and 47 tons/year of VOC.

Note that the project requires the shutdown of the existing Unit 2 boiler, which provided emissions decreases and allowed the project to avoid PSD preconstruction review. Potential annual emissions are based on: the permitted emissions standards; the operational restrictions in the permit; a maximum heat input rate from firing natural gas of 1795 MMBtu per hour at compressor inlet temperature of 59° F; and a maximum heat input rate from firing distillate oil of 1979 MMBtu per hour at compressor inlet temperature of 59° F.}

[Application No. 0730003-009-AC; Rule 62-4.070(3), F.A.C; Rule 62-212.400(12)(Source Obligation), F.A.C. for the CO Emissions Cap]

13. Ammonia Slip: The SCR system shall be designed to achieve a maximum ammonia slip of 5 ppmvd @ 15% oxygen. Actual ammonia slip levels shall not exceed 10 ppmvd @ 15% oxygen as determined by EPA Method CTM-027 based on the average of three test runs. If tests indicate an ammonia slip level greater than 5 ppmvd @ 15% oxygen, the permittee shall:

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

    b. Before the ammonia slip exceeds 10 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

    c. Test and demonstrate that the ammonia slip is less than 5 ppmvd corrected to 15% oxygen within 45 days after completing the corrective actions.

    Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

14. Applicable NSPS Provisions: In addition to the above standards, the combustion turbine system shall be designed, operated, and maintained to achieve the following federal New Source Performance Standards (NSPS) in 40 CFR 60: Subpart A (General Provisions) and Subpart KKKK (New Combustion Turbines and Duct Burners). In summary the emissions standards are:

    a. Pursuant to §60.4320 and Table 1, the NSPS Subpart KKKK NOx standard for gas firing is 15 ppmvd @ 15% oxygen based on a 30-day rolling average for combined cycle operation and 15 ppmvd @ 15% oxygen based on a 4-hour rolling average for simple cycle HRSG/SCR bypass operation.

    b. Pursuant to §60.4320 and Table 1, the NSPS Subpart KKKK NOx standard for oil firing is 42 ppmvd @ 15% oxygen based on a 30-day rolling average for combined cycle operation.

    c. Pursuant to §60.4330(a)(2), SO_2 emissions are limited in NSPS Subpart KKKK by a prohibition on the firing of any fuels that contain total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input.

    See Appendix D of this permit for the full NSPS requirements. [40 CFR 60, Subparts A and KKKK]

15. Applicable NESHAP Provisions: In addition to the above standards, the combustion turbine system shall be designed, operated, and maintained to achieve the following federal National Emissions Standards for Hazardous Air Pollutants (NEHSAP) in 40 CFR 63: Subpart A (General Provisions) and Subpart YYYY (Combustion Turbines). *{Permitting Note: On August 18, 2004, EPA stayed the effectiveness of NESHAP Subpart YYYY for lean premix and diffusion flame combustion turbines. When the stay is lifted, the regulation may be revised. It is uncertain at this time whether or not the combustion turbine will be subject to a formaldehyde limit with emissions testing or an oxidation catalyst will be required or some other set of requirements.}* [40 CFR 63, Subparts A and YYYY]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition 12 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal NSPS, NESHAP, or Acid Rain provision.}

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. [Rule 62-210.700(4), F.A.C.]

17. 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.

18. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, malfunction, fuel switches, and DLN/SCR/WI tuning are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such events. For excess emissions events that last less than the maximum duration allowed, only those minutes attributable to excess emissions from the event shall be excluded. When authorized, excess emissions data shall be excluded from a compliance determination as a continuous block attributed to the event.

    a. *Startup*:

        1) Steam Turbine Generator Cold Startup: No more than the first 600 minutes of CEMS data shall be excluded due to excess emissions from a steam turbine generator cold startup. A "steam turbine generator cold startup" is defined as startup after the steam turbine generator has been offline for 24 hours or more, or the first stage turbine metal temperature is 250°F or less.

        2) Steam Turbine Generator Warm Startup: No more than the first 300 minutes of CEMS data shall be excluded due to excess emissions from a steam turbine generator warm startup. A "steam turbine generator warm startup" is defined as startup to combined cycle operation when the gas turbine has been shut down for a period of time and the first stage steam turbine metal temperature is greater than 250°F.

        3) Steam Turbine Generator Hot Startup: No more than the first 240 minutes of CEMS data shall be excluded due to excess emissions from a steam turbine generator hot startup. A "steam turbine generator hot startup" is defined as startup of the steam turbine generator while the unit has been operating in the combined cycle mode with the steam being dumped to the condenser.

        4) Simple Cycle HRSG/SCR Bypass Startup: No more than the first 30 minutes of CEMS data shall be excluded due to excess emissions from a simple cycle gas turbine startup in which exhaust is directed to the HRSG/SCR bypass stack.

    b. *Shutdown*: No more than the first 30 minutes of CEMS data shall be excluded due to excess emissions from a combustion turbine shutdown. For shutdowns of less than 30 minutes in duration, only those minutes attributable to excess emissions from shutdown shall be excluded.

    c. *Malfunction*: No more than 120 minutes of CEMS data shall be excluded in a 24-hour period due to excess emissions from malfunction. 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.

    d. *Fuel Switch*: No more than the first 30 minutes of CEMS data shall be excluded due to excess emissions from a fuel switch. For fuel switches less than 30 minutes in duration, only those minutes attributable to excess emissions from fuel switching shall be excluded.

    e. *DLN/SCR/WI Tuning*: No more than 72 hours of CEMS data during any consecutive 12 months shall be excluded from the CEMS compliance demonstration due to excess emissions from the necessary tuning of the dry low-NOx (DLN) combustion system, the selective catalytic reduction (SCR) system, or the water injection (WI) system. Tuning sessions shall be performed in accordance with the manufacturer's recommendations or industry standards. Prior to performing any DLN, SCR, or WI tuning session, the permittee shall provide the Compliance Authority with an advance notice (telephone, facsimile transmittal, or electronic mail) that details the activity and proposed tuning schedule. *{Permitting Note: DLN tuning sessions are typically required after completion of initial construction, a combustor change-out, a major repair, a unit overhaul, maintenance to a combustor, or other similar circumstances. During DLN or water injection tuning, the SCR system is turned off and the combustion* *turbine is sequentially stepped through numerous loads (including low load levels) to gather actual emissions data and operational information for use in adjusting the combustion turbine and control system.}*

CEMS data shall only be excluded in accordance with the procedures described in the Condition 21 of this section (CEMS Data Requirements). As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for the specifically defined periods. Data exclusion does not apply to the CO emissions cap based on a 12-month rolling total. [Application No. 0730003-009-AC; Design; Rule 62-210.700(5), F.A.C.]

19. Alternate Visible Emissions Standard: Visible emissions due to startup shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-210.700(5), F.A.C.]

CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) REQUIREMENTS

20. CEMS: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NOx from the combustion turbine HRSG exhaust stack in a manner sufficient to demonstrate continuous compliance with the CEMS-based emission standards of this section. Within 60 days of achieving permitted capacity, but no later than 180 days after first fire, all continuous emissions monitoring systems shall be installed, certified and functioning properly.

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

    b. *NOx Monitor:* The 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 RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

    c. *Diluent 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. The monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

    [Rules 62-4.070(3), 62-210.800, and 62-297.520, F.A.C.]

21. CEMS Data Requirements: The CEMS shall be installed, calibrated, maintained, and operated in the combustion turbine exhaust stacks to measure and record the emissions of CO, and NOx in a manner sufficient to demonstrate compliance with the CEMS-based emission limits standards of this section. The CEMS shall express the results in units of ppmvd corrected to 15% oxygen.

    a. *Valid Hourly Averages for Compliance:* 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. Except for allowable emissions data exclusions, 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. Each 1-hour block average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, there is insufficient data and the 1-hour block average is not valid. Also, if an allowable exclusion episode should occur over two separate hourly averages, only those minutes attributed to the specific episode shall be excluded from each hour.

    b. *30-day Rolling Averages:* A 30-day rolling average shall be calculated from all valid hourly averages collected during the given operating day and the previous 29 operating days. For purposes of determining compliance with the 30-day rolling NOx standard, the missing data substitution methodology of 40 CFR Part 75, Subpart D, shall not be utilized. Instead, the 30-day rolling average shall be determined using the remaining hourly data and periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance reports. *{Permitting Note: Condition 22 defines the use of "maximum permitted emission levels" for* *use when the combustion turbine operates in simple cycle mode.}*

c. *12-Month Rolling Total*: By the end of each month, the CO CEMS shall also determine a 12-month rolling total of CO emissions from the combustion turbine. The 12-month rolling total shall be based on all valid CO CEMS data collected (including startups, shutdowns, and malfunctions) for the given month and the previous 11 months.

d. *Data Exclusion*: Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall monitor and record emissions during all operations including episodes of startups, shutdowns, malfunctions, and DLN tuning. Limited amounts of CEMS emissions data recorded during some of these episodes may be excluded from the corresponding compliance demonstration subject to the provisions of Condition 18 in this section. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable.

e. *Monitor Availability*. Monitor availability for each CEMS used to demonstrate compliance shall be 95% or greater in any calendar quarter. Monitor availability shall be calculated consistent with Subpart KKKK in 40 CFR 60 and reported in the SIP and NSPS excess emissions reports required in Condition 36. In the event that 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Compliance Authority.

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

22. Simple Cycle HRSG/SCR Bypass Operation: Because the bypass stack will only be used in emergency situations where the HRSG, SCR and/or steam turbine-generator are unavailable, the permittee is not required to install CO/NOx CEMS or permanent test ports on the bypass stack. When an emergency situation occurs, the permittee shall ensure that the unit is firing only natural gas and is properly operating with lean premix combustion (Mode 6). The permittee shall monitor the hours of operation in simple cycle HRSG/SCR bypass mode and use the following methods to determine CO and NOx emissions.

    a. Compliance with the NOx and CO emission standards for the simple cycle HRSG/SCR bypass mode of operation shall be demonstrated by conducting initial and annual tests as required by Condition 26 of this section.

    b. Compliance with the 12-month rolling CO emissions cap, the maximum CO mass emission rate of 41.7 lb/hour shall be used to represent each hour of operation in this mode.

    If the unit operates in simple cycle mode for a substantial period of time, the Compliance Authority may request additional CO and NOx testing to demonstrate compliance with the standards. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

    {Permitting Note: The above sampling method is similar to the method allowed under the Acid Rain program for bypass stack situations as described in 40 CFR 75.17(d)(2).}

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

EMISSIONS PERFORMANCE TESTING

24. Continuous Compliance: Continuous compliance with the CO and NOx emissions standards shall be demonstrated with data collected from the required continuous emissions monitoring systems (CEMS). The permittee shall submit an initial compliance report in accordance with Condition 30 of this section. [Rules 62-4.070(3) and 62-297.310(7)(a) and (b), F.A.C.]

25. Operational Rate During Testing: Initial and subsequent performance tests shall be conducted between 90% and 100%

of permitted capacity for the given compressor inlet conditions in accordance with the requirements of Rule 62-297.310(2), F.A.C. [Rule 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

26. Initial Compliance Tests: In accordance with the test methods specified in this section, 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.

    a. The HRSG stack shall be tested on each authorized fuel in combined cycle mode to demonstrate compliance with the standards for ammonia slip and visible emissions. For each required test, emissions of CO and NOx recorded by the CEMS shall also be reported.

    b. The simple cycle HRSG/SCR bypass operation shall be tested when firing natural gas in simple cycle mode to demonstrate compliance with the permitted CO and NOx emissions standards. For this method of operation, tests may be conducted by taking the SCR system out of service and sampling at the HRSG stack. In addition, the installed and certified CO and NOx CEMS may be used to provide the compliance test data. These tests shall consist of at least four, 1-hour test runs to determine the 4-hour average.

    [Rules 62-4.070(3) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

27. Annual Compliance Testing: During each federal fiscal year (October 1st to September 30th), annual compliance tests shall be conducted in accordance with the test method specified in this section.

    a. The HRSG stack shall be tested on natural gas in combined cycle mode to demonstrate compliance with the standards for ammonia slip and visible emissions. For each required test, emissions of CO and NOx recorded by the CEMS shall also be reported. If distillate oil is fired for more than 400 hours during the federal fiscal year, the HRSG stack shall also be tested on oil in combined cycle mode to demonstrate compliance with the standards for ammonia slip and visible emissions.

    b. The simple cycle HRSG/SCR bypass operation shall be tested when firing natural gas in simple cycle mode to demonstrate compliance with the permitted CO and NOx emissions standards. For this method of operation, tests may be conducted by taking the SCR system out of service and sampling at the HRSG stack. In addition, the installed and certified CO and NOx CEMS may be used to provide the compliance test data. These tests shall consist of at least four, 1-hour test runs to determine the 4-hour average.

    [Rules 62-4.070(3) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

28. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. [Rule 62-297.310(7)(a)9, F.A.C.]

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

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental)
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

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 Department. Tests shall be conducted in accordance with the appropriate test method, the applicable requirements specified in Appendix C of this permit, and the applicable NSPS and NESHAP in 40 CFR Parts 60 and 63, respectively. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR Parts 60 and 63]

REPORTING AND RECORD KEEPING REQUIREMENTS

30. CEMS Report - Initial Operation: For the first two calendar quarters of operation, the permittee shall submit a report summarizing the CO and NOx emissions as determined by CEMS data. Emissions rates shall be reported in terms of

ppmvd @ 15% oxygen for the 30-day rolling averages. CO emissions shall also be reported in "tons per month". Reports shall be submitted within 30 days of each calendar quarter. [Rule 62-4.070(3), F.A.C.]

31. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the combustion turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, and DLN tuning). 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 system required above. [Rule 62-4.070(3), F.A.C.; 40 CFR 75]

32. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the previous month and the previous consecutive 12 months: total heat input rate to the combustion turbine from each fuel (MMBtu); the total heat input rate to the duct burner (MMBtu); and the 12-month rolling total of CO emissions (tons). 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. Fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3), F.A.C.]

33. Fuel Sulfur Records: The sulfur content of the distillate oil shall be determined by ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. For each fuel oil delivery, the permittee shall record and retain the following information: the date; gallons delivered; and a fuel oil analysis including the heat content in MMBtu/gallon, the density in pounds/gallon, the sulfur content in percent by weight, and the name of the test method used. A certified analysis supplied by the fuel oil vendor is acceptable. Alternatively, the monitoring methods specified in § 60.4370 are sufficient to demonstrate compliance with the maximum fuel sulfur levels for distillate oil established in this permit. [Rule 62-4.070(3), F.A.C.; 40 CFR 60.4370]

34. Stack Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Compliance Authority to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the applicable information specified in Rule 62-297.310(8), F.A.C. and summarized in Appendix C. [Rule 62-297.310(8), F.A.C.]

35. CEMS RATA Reports: At least 15 days prior to conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall notify the Compliance Authority of the schedule (letter, email, fax, or phone call). In addition to filing reports with the Department's Bureau of Air Monitoring and Mobile Sources, a summary of the RATA reports shall be submitted to the Compliance Authority within 45 days of completing the RATA. [Rules 62-4.070(3), F.A.C.]

36. Excess Emissions Reporting

a. *Malfunction Notification:* If NOx data will be excluded due to a malfunction, the permittee shall notify the Compliance Authority within one 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 Compliance Authority may request a written summary report of the incident.

b. *SIP Excess Emissions Report*: Within 30 days following the end of June and December of each year, the permittee shall submit a report to the Compliance Authority summarizing the following for the combustion turbine for the period: a summary of the CO and NOx compliance periods; a summary of CO and NOx data excluded due to malfunctions; a summary of the 12-month rolling CO emissions totals; a summary of any RATA tests performed; and a summary of the CEMS systems monitor availability for each quarter during the period.

c. *NSPS Excess Emissions Reports*: Within thirty (30) days following the end of June and December of each year, the permittee shall submit a report including any applicable periods of excess emissions and monitoring systems performance as defined in 40 CFR 60 Subpart KKKK that occurred during the previous semi-annual period to the Compliance Authority. *{Permitting Note: If there are no periods of excess emissions as defined in Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}*

[Rules 62-4.070(3), 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7, 60.4375, and 60.4395]

37. Initial Report on Startups: The permittee shall submit a report summarizing the following information for each startup during the first 12 months of operation: the type of startup; the sequence of events for the startup; the duration of the startup; CO and NOx hourly emissions averages recorded for each hour of the startup (lb/hour and ppmvd @ 15% oxygen); total CO and NOx mass emissions rates for each startup (pounds). The report is due within 60 days following the 12th month of operation for the unit. Based on the actual information, the Department may reduce the duration of data allowed to be excluded as excess emissions due to the startup event through an air construction permit modification. [Rules 62-4.070(3) and 62-210.700(5), F.A.C.]

CONTENTS

CITATION FORMATS

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

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

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

Where: "AC" identifies the permit as an Air Construction Permit

"AO" identifies the permit as an Air Operation Permit

"123456" identifies the specific permit project number

New Permit Numbers

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

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

"2222" represents the specific facility ID number

"001"identifies the specific permit project

"AC" identifies the permit as an air construction permit

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

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

"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

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

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

"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (Not Applicable);
    b. Determination of Prevention of Significant Deterioration (Not Applicable); and
    c. Compliance with New Source Performance Standards (Not 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

{Permitting Note: Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.}

EMISSIONS AND CONTROLS

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

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

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

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

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

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

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

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]

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

TESTING REQUIREMENTS

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

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

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

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

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

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

14. Determination of Process Variables

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

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

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

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

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

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

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

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

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

RECORDS AND REPORTS

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

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

NSPS SUBPART KKKK PROVISIONS

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

On July 6, 2006, EPA published the final NSPS Subpart KKKK (40 CFR 60) provisions for combustion turbines in the Federal Register. Although not yet adopted by Rule 62-204.800(8), F.A.C., the combustion turbine shall comply with the applicable federal requirements.

NSPS SUBPART A, 40 CFR 60 - GENERAL PROVISIONS

The permittee shall comply with the applicable general provisions identified in Table 7 of 40 CFR 63 Subpart YYYY.

NSPS SUBPART KKKK, 40 CFR 60 – STATIONARY COMBUSTION TURBINES

Provisions that do not apply to this project have been omitted. Numbering remains consistent with the NSPS Subpart.

Sec. 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.

Sec. 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.

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

No applicable provisions.

Sec. 60.4315 What pollutants are regulated by this subpart?

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

Sec. 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.

Sec. 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.

Sec. 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.

   (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.

Sec. 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.

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

(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); and

Sec. 60.4340 How do I demonstrate continuous compliance for NOx if I do not use water or steam injection?

(a) S*imple Cycle HRSG/SCR Bypass Operation (for this project):* If you are not using water or steam injection to control NOx emissions, you must perform annual performance tests in accordance with Sec. 60.4400 to demonstrate continuous compliance. If the NOx emission result from the performance test is less than or equal to 75 percent of the NOx 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 NOx 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 Sec. 60.4335(b) and Sec. 60.4345 *for combined cycle operation for this project.*

(2) Continuous parameter monitoring *for simple cycle HRSG/SCR bypass operation for this project* as follows:

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOx mode.

Sec. 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 Sec. 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 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.

(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.

Sec. 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 Sec. 60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in Sec. 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 Sec. 60.7(c).

(e) All required fuel flow rate data must be reduced to hourly averages.

(f) Calculate the hourly average NOx emission rates, in units of the emission standards under Sec. 60.4320, using either ppm for units complying with the concentration limit.

(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 Sec. 60.4380(b)(1).

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

(a) The parameters that are continuously monitored as described in Sec. Sec. 60.4335 and 60.4340 must be monitored during the performance test required under Sec. 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 NOx 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 NOx 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.

(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.

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

No applicable provisions.

Sec. 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 tariff sheet or specifying that the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet; 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.

Sec. 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 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., 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).

Sec. 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 Sec. 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 Sec. 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.

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

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

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

(1) An excess emissions is any unit operating period in which the 30-day rolling average NOx emission rate exceeds the applicable emission limit in Sec. 60.4320. For the purposes of this subpart, a "30-day rolling average NOx emission rate" is the arithmetic average of all hourly NOx 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 NOx emissions rates for the preceding 30 unit operating days if a valid NOx 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: NOx concentration, CO_2 or O_2 concentration, fuel flow rate.

(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 NOx 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.

Sec. 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:

(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.

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

No applicable provisions.

(a) If you operate an emergency combustion turbine, you are exempt from the NOx 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 NOx limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

Sec. 60.4395 When must I submit my reports?

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

Sec. 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 Sec. 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) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NOx concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part.

(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 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 NOx concentration during the stratification test; or

(B) For Turbines with a NOx standard greater than 15ppm @ 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 3ppm or 0.3 percent CO2 (or O2) from the mean for all traverse points; or

(C) For turbines with a NOx standard less than or equal 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 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 NOx emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(4) Compliance with the applicable emission limit in Sec. 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 Sec. 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 Sec. 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.

Sec. 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 NOX-diluent CEMS under Sec. 60.4345, then the initial performance test required under Sec. 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.

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

(d) Compliance with the applicable emission limit in Sec. 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.

Sec. 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 NOx emission controls in accordance with Sec. 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 Sec. 60.4355.

Sec. 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 Sec. 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 Sec. 60.17) for natural gas or ASTM D4177 (incorporated by reference, see Sec. 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 Sec. 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 Sec. 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 Sec. 60.17).

(b) [Reserved]

Sec. 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.

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.

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.

Excess emissions means a specified averaging period over which either (1) the NOx emissions are higher than the applicable emission limit in Sec. 60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in Sec. 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.

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 Stationary Combustion Turbines

Combustion Turbine Type	Combustion Turbine Heat Input Rate at Peak Load (HHV)	NOx Emission Standard
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, 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)

NESHAP SUBPART YYYY PROVISIONS

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP)

New combustion turbines are subject to the NESHAP provisions of Subpart YYYY in 40 CFR 63. However, on August 18, 2004, EPA stayed the effectiveness of NESHAP Subpart YYYY for lean premix and diffusion flame gas turbines. The relevant provision of the rule that stays the effectiveness for such units is as follows.

40 CFR 63.6095(d) Stay of Standards for Gas-Fired Subcategories.

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

NESHAP SUBPART A, 40 CFR 63 - GENERAL PROVISIONS

The permittee shall comply with the applicable general provisions identified in Table 7 of 40 CFR 63 Subpart YYYY.

NESHAP SUBPART YYYY – STATIONARY COMBUSTION TURBINES

40 CFR 63.6080 What is the purpose of subpart YYYY?

Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

40 CFR 63.6085 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions.

(a) *No applicable requirements.*

(b) A major source of HAP emissions is a contiguous site under common control that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

40 CFR 63.6090 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) Affected source. An affected source is any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions.

  (2) New stationary combustion turbine. A stationary combustion turbine is new if you commenced construction of the stationary combustion turbine after January 14, 2003.

(b) *No applicable requirements.*

40 CFR 63.6092 Are duct burners and waste heat recovery units covered by subpart YYYY?

No, duct burners and waste heat recovery units are considered steam generating units and are not covered under this subpart. In some cases, it may be difficult to separately monitor emissions from the turbine and duct burner, so sources are allowed to meet the required emission limitations with their duct burners in operation.

40 CFR 63.6095 When do I have to comply with this subpart?

(a) Affected sources.

  (1) *No applicable requirements.*

(2) If you start up a new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart after March 5, 2004, you must comply with the emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *No applicable requirements.*

(c) You must meet the notification requirements in Sec. 63.6145 according to the schedule in Sec. 63.6145 and in 40 CFR part 63, subpart A.

40 CFR 63.6100 What emission and operating limitations must I meet?

For each new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart, you must comply with the emission limitations and operating limitations in Table 1 and Table 2 of this subpart.

40 CFR 63.6105 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations which apply to you at all times except during startup, shutdown, and malfunctions.

(b) If you must comply with emission and operating limitations, you must operate and maintain your stationary combustion turbine, oxidation catalyst emission control device or other 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.

40 CFR 63.6110 By what date must I conduct the initial performance tests or other initial compliance demonstrations?

(a) You must conduct the initial performance tests or other initial compliance demonstrations in Table 4 of this subpart that apply to you within 180 calendar days after the compliance date that is specified for your stationary combustion turbine in Sec. 63.6095 and according to the provisions in Sec. 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test to determine outlet formaldehyde concentration on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (b)(5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

40 CFR 63.6115 When must I conduct subsequent performance tests?

Subsequent performance tests must be performed on an annual basis as specified in Table 3 of this subpart.

40 CFR 63.6120 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Table 3 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements of the General Provisions at Sec. 63.7(e)(1) and under the specific conditions in Table 2 of this subpart.

(c) Do not conduct performance tests or compliance evaluations during periods of startup, shutdown, or malfunction. Performance tests must be conducted at high load, defined as 100 percent plus or minus 10 percent.

(d) You must conduct three separate test runs for each performance test, and each test run must last at least 1 hour.

(e) If your stationary combustion turbine is not equipped with an oxidation catalyst, you must petition the Administrator for operating limitations that you will monitor to demonstrate compliance with the formaldehyde emission limitation in Table 1. You must measure these operating parameters during the initial performance test and continuously monitor thereafter. Alternatively, you may petition the Administrator for approval of no additional operating limitations. If you submit a petition under this section, you must not conduct the initial performance test until after the petition has been approved or disapproved by the Administrator.

(f) If your stationary combustion turbine is not equipped with an oxidation catalyst and you petition the Administrator for approval of additional operating limitations to demonstrate compliance with the formaldehyde emission limitation in Table 1, your petition must include the following information described in paragraphs (f)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as additional operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(g) If you petition the Administrator for approval of no additional operating limitations, your petition must include the information described in paragraphs (g)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary combustion turbine and any emission control device which could change intentionally (e.g., operator adjustment, automatic controller adjustment, etc.) or unintentionally (e.g., wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of why establishing limitations on the parameters is not possible;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of why you could not establish upper and/or lower values for the parameters which would establish limits on the parameters as operating limitations;

(5) For the parameters which could change in such a way as to increase HAP emissions, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible, unreasonable or unnecessary to adopt the parameters as operating limitations.

40 CFR 63.6125 What are my monitor installation, operation, and maintenance requirements?

(a) *No applicable requirements.*

(b) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you are not using an oxidation catalyst, you must continuously monitor any parameters specified in your approved petition to the Administrator, in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.

(c) *No applicable requirements.*

(d) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must monitor and record your distillate oil usage daily for all new and existing stationary combustion turbines located at the major source with a non-re-settable hour meter to measure the number of hours that distillate oil is fired.

40 CFR 63.6130 How do I demonstrate initial compliance with the emission and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 4 of this subpart.

(b) You must submit the Notification of Compliance Status containing results of the initial compliance demonstration according to the requirements in Sec. 63.6145(f).

40 CFR 63.6135 How do I monitor and collect data to demonstrate continuous compliance?

(a) Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), you must conduct all parametric monitoring at all times the stationary combustion turbine is operating.

(b) Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. You must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine.

40 CFR 63.6140 How do I demonstrate continuous compliance with the emission and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Table 1 and Table 2 of this subpart according to methods specified in Table 5 of this subpart.

(b) You must report each instance in which you did not meet each emission imitation or operating limitation. You must also report each instance in which you did not meet the requirements in Table 7 of this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in Sec. 63.6150.

(c) Consistent with Sec. 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, and malfunction are not violations if you have operated your stationary combustion turbine in full conformity with all provisions of your startup, shutdown, and malfunction plan, and you have otherwise satisfied the general duty to minimize emissions established by Sec. 63.6(e)(1)(i).

40 CFR 63.6145 What notifications must I submit and when?

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

(b) *No applicable requirements.*

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

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

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

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

40 CFR 63.6150 What reports must I submit and when?

(a) Anyone who owns or operates a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report according to Table 6 of this subpart. The semiannual compliance report must contain the information described in paragraphs (a)(1) through (a)(4) of this section. The semiannual compliance report must be submitted by the dates specified in paragraphs (b)(1) through (b)(5) of this section, unless the Administrator has approved a different schedule.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) For each deviation from an emission limitation, the compliance report must contain the information in paragraphs (a)(4)(i) through (a)(4)(iii) of this section.

(i) The total operating time of each stationary combustion turbine during the reporting period.

(ii) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(iii) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(b) Dates of submittal for the semiannual compliance report are provided in (b)(1) through (b)(5) of this section.

(1) The first semiannual compliance report must cover the period beginning on the compliance date specified in Sec. 63.6095 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date specified in Sec. 63.6095.

(2) The first semiannual compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified in Sec. 63.6095.

(3) Each subsequent semiannual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent semiannual compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports

according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) *No applicable requirements.*

(d) *No applicable requirements.*

(e) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must submit an annual report according to Table 6 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (d)(1) through (5) of this section. You must report the data specified in (e)(1) through (e)(3) of this section.

(1) The number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

40 CFR 63.6155 What records must I keep?

(a) You must keep the records as described in paragraphs (a)(1) through (5).

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirements in Sec. 63.10(b)(2)(xiv).

(2) Records of performance tests and performance evaluations as required in Sec. 63.10(b)(2)(viii).

(3) Records of the occurrence and duration of each startup, shutdown, or malfunction as required in Sec. 63.10(b)(2)(i).

(4) Records of the occurrence and duration of each malfunction of the air pollution control equipment, if applicable, as required in Sec. 63.10(b)(2)(ii).

(5) Records of all maintenance on the air pollution control equipment as required in Sec. 63.10(b)(iii).

(b) If you are operating a stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis, or if you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must keep the records of your daily fuel usage monitors.

(c) You must keep the records required in Table 5 of this subpart to show continuous compliance with each operating limitation that applies to you.

40 CFR 63.6160 In what form and how long must I keep my records?

(a) You must maintain all applicable records in such a manner that they can be readily accessed and are suitable for inspection according to Sec. 63.10(b)(1).

(b) As specified in Sec. 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must retain your records of the most recent 2 years on site or your records must be accessible on site. Your records of the remaining 3 years may be retained off site.

40 CFR 63.6165 What parts of the General Provisions apply to me?

Table 7 of this subpart shows which parts of the General Provisions in Sec. 63.1 through 15 apply to you.

40 CFR 63.6170 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under section 40 CFR Part 63, Subpart E, the authorities contained in paragraph (c) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the emission limitations or operating limitations in Sec. 63.6100 under Sec. 63.6(g).

(2) Approval of major alternatives to test methods under Sec. 63.7(e)(2)(ii) and (f) and as defined in Sec. 63.90.

(3) Approval of major alternatives to monitoring under Sec. 63.8(f) and as defined in Sec. 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under Sec. 63.10(f) and as defined in Sec. 63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule to determine outlet formaldehyde concentration, as specified in Sec. 63.6110(b).

40 CFR 63.6175 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA; in 40 CFR 63.2, the General Provisions of this part; and in this section:

Area source means any stationary source of HAP that is not a major source as defined in this part.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary reciprocating internal combustion engines.

CAA means the Clean Air Act (42 U.S.C. 7401 et seq., as amended by Public Law 101-549, 104 Stat. 2399).

Combined cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger to generate steam for use in a steam turbine.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit;

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless of whether or not such failure is permitted by this subpart; or

(4) Fails to conform to any provision of the applicable startup, shutdown, or malfunction plan, or to satisfy the general duty to minimize emissions established by Sec. 63.6(e)(1)(i).

Diffusion flame oil-fired stationary combustion turbine means:

(1) (i) Each stationary combustion turbine which is equipped only to fire oil using diffusion flame technology, and

(ii) Each stationary combustion turbine which is equipped both to fire oil using diffusion flame technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil.

(2) Diffusion flame oil-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine, or

(ii) Any stationary combustion turbine located on the North Slope of Alaska.

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

Distillate oil means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2.

Hazardous air pollutant (HAP) means any air pollutant listed in or pursuant to section 112(b) of the CAA.

ISO standard day conditions means 288 degrees Kelvin (15<DEGC), 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix gas-fired stationary combustion turbine means:

(1) (i) Each stationary combustion turbine which is equipped only to fire gas using lean premix technology,

(ii) Each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, during any period when it is firing gas, and

(iii) Each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

(2) Lean premix gas-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine,

(ii) Any stationary combustion turbine located on the North Slope of Alaska, or

(iii) Any stationary combustion turbine burning landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or any stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis.

Lean premix oil-fired stationary combustion turbine means:

(1) (i) Each stationary combustion turbine which is equipped only to fire oil using lean premix technology, and

(ii) Each stationary combustion turbine which is equipped both to fire oil using lean premix technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil.

(2) Lean premix oil-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine, or

(ii) Any stationary combustion turbine located on the North Slope of Alaska.

Lean premix technology means a configuration of a stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber.

Major source, as used in this subpart, shall have the same meaning as in Sec. 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in this section, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in this section, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes or has the potential to cause the emission limitations in this standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. May be field or pipeline quality. For the purposes of this subpart, the definition of natural gas includes similarly constituted fuels such as field gas, refinery gas, and syngas.

Oxidation catalyst emission control device means an emission control device that incorporates catalytic oxidation to reduce CO emissions.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in Sec. 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to Sec. 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to Sec. 63.1270(a)(2).

Simple cycle stationary combustion turbine means any stationary combustion turbine that does not recover heat from the stationary combustion turbine exhaust gases.

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), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Tables to Subpart YYYY of Part 63.

As stated in § 63.6100, you must comply with the following emission limitations:

TABLE 1 TO SUBPART YYYY OF PART 63 - EMISSIONS LIMITATIONS

For each new or reconstructed stationary combustion turbine described in § 63.6100 which is	You must meet the following emission limitations
1. a lean premix gas-fired stationary combustion turbine as defined in this subpart, 2. a lean premix oil-fired stationary combustion turbine as defined in this subpart, 3. a diffusion flame gas-fired stationary combustion turbine as defined in this subpart, or 4. a diffusion flame oil-fired stationary combustion turbine as defined in this subpart.	limit the concentration of formaldehyde to 91 ppbvd or less at 15 percent O_2.

As stated in §§ 63.6100 and 63.6140, you must comply with the following operating limitations:

TABLE 2 TO SUBPART YYYY OF PART 63. - OPERATING LIMITATIONS

For	You must
1. Each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is using an oxidation catalyst.	Maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer.
2. Each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is not using an oxidation catalyst.	Maintain any operating limitations approved by the Administrator.

As stated in § 63.6120, you must comply with the following requirements for performance tests and initial compliance demonstrations:

TABLE 3 TO SUBPART YYYY OF PART 63. - REQUIREMENTS FOR PERFORMANCE TESTS AND INITIAL COMPLIANCE DEMONSTRATIONS

You must	Using	According to the following requirements
a. Demonstrate formaldehyde emissions meet the emission limitations specified in Table 1 by a performance test initially and on an annual basis AND.	Test Method 320 of 40 CFR part 63, appendix A; ASTM D6348–03 provided that %R as determined in Annex A5 of ASTM D6348– 03 is equal or greater than 70% and less than or equal to 130%; or other methods approved by the Administrator.	Formaldehyde concentration must be corrected to 15 percent O2, dry basis. Results of this test consist of the average of the three 1 hour runs. Test must be conducted within 10 percent of 100 percent load.
b. Select the sampling port location and the number of traverse points AND.	Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	If using an air pollution control device, the sampling site must be located at the outlet of the air pollution control device.
c. Determine the O_2 concentration at the sampling port location AND.	Method 3A or 3B of 40 CFR part 60, appendix A.	Measurements to determine O_2 concentration must be made at the same time as the performance test.
d. Determine the moisture content at the sampling port location for the purposes of correcting the formaldehyde concentration to a dry basis.	Method 4 of 40 CFR part 60, appendix A or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.	Measurements to determine moisture content must be made at the same time as the performance test.

As stated in §§ 63.6110 and 63.6130, you must comply with the following requirements to demonstrate initial compliance with emission limitations:

TABLE 4 TO SUBPART YYYY OF PART 63. - INITIAL COMPLIANCE WITH EMISSION LIMITATIONS

For the	You have demonstrated initial compliance if
Emission limitation for formaldehyde.	The average formaldehyde concentration meets the emission limitations specified in Table 1.

As stated in §§ 63.6135 and 63.6140, you must comply with the following requirements to demonstrate continuing compliance with operating limitations:

TABLE 5 OF SUBPART YYYY OF PART 63. - CONTINUOUS COMPLIANCE WITH OPERATING LIMITATIONS

For each stationary combustion turbine complying with the emission limitation for formaldehyde	You must demonstrate continuous compliance by
1. With an oxidation catalyst	Continuously monitoring the inlet temperature to the catalyst and maintaining the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer.
2. Without the use of an oxidation catalyst	Continuously monitoring the operating limitations that have been approved in your petition to the Administrator.

As stated in § 63.6150, you must comply with the following requirements for reports:

TABLE 6 OF SUBPART YYYY OF PART 63. - REQUIREMENTS FOR REPORTS

If you own or operate a	You must	According to the following requirements
1. Stationary combustion turbine which must comply with the formaldehyde emission limitation.	report your compliance status	semiannually, according to the requirements of § 63.6150.
2. Stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis.	Report: (1) the fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas, digester gas, or gasified MSW is equivalent to 10 percent or more of the gross heat input on an annual basis, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters.	annually, according to the requirements in § 63.6150.
3. A lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source.	Report: (1) the number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters.	annually, according to the requirements in § 63.6150.

TABLE 7 OF SUBPART YYYY OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART YYYY

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.1	General applicability of the General Provisions.	Yes	Additional terms defined in §63.6175.
§63.2	Definitions	Yes	Additional terms defined in §63.6175.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources.	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved].		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major.	Yes.	
§63.6(c)(1)–(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)–(4)	[Reserved].		
§63.6(c)(5)	Compliance dates for existing area sources that become major.	Yes.	
§63.6(d)	[Reserved].		
§63.6(e)(1)	Operation and maintenance	Yes.	
§63.6(e)(2)	[Reserved].		
§63.6(e)(3)	SSMP	Yes.	
§63.6(f)(1)	Applicability of standards except during startup, shutdown, or malfunction (SSM).	Yes.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)–(3)	Use of alternative standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart YYYY does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria.	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)–(2)	Performance test dates	Yes	Subpart YYYY contains performance test dates at §63.6110.
§63.7(a)(3)	Section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes.	
§63.7(b)(2)	Notification of rescheduling	Yes.	
§63.7(c)	Quality assurance/test plan	Yes.	
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests.	Yes.	
§63.7(e)(2)	Conduct of performance tests and reduction of data.	Yes	Subpart YYYY specifies test methods at §63.6120.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA.	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting.	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart YYYY contains specific requirements for monitoring at §63.6125.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved].		
§63.8(a)(4)	Monitoring for control devices	No.	

TABLE 7 OF SUBPART YYYY OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART YYYY—Continued

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems.	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance.	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§63.8(c)(1)(ii)	Parts for repair of CMS readily available	Yes.	
§63.8(c)(1)(iii)	SSMP for CMS required	Yes.	
§63.8(c)(2)–(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements.	Yes	Except that subpart YYYY does not require continuous opacity monitoring systems (COMS).
§63.8(c)(5)	COMS minimum procedures	No.	
§63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart YYYY does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
§63.8(f)(1)–(5)	Alternative monitoring method	Yes.	
§63.8(f)(6)	Alternative to relative accuracy test	Yes.	
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6135 and 63.6140.
§63.9(a)	Applicability and State delegation of notification requirements.	Yes.	
§63.9(b)(1)–(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
§63.9(c)	Request for compliance extension	Yes.	
§63.9(d)	Notification of special compliance requirements for new sources.	Yes.	
§63.9(e)	Notification of performance test	Yes.	
§63.9(f)	Notification of visible emissions/opacity test.	No	Subpart YYYY does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes.	
§63.9(g)(2)	Notification of use of COMS data	No	Subpart YYYY does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to relative accuracy test audit (RATA) is exceeded.	Yes	If alternative is in use.
§63.9(h)	Notification of compliance status	Yes	Except that notifications for sources not conducting performance tests are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for record-keeping and reporting.	Yes.	
§63.10(b)(1)	Record retention	Yes.	
§63.10(b)(2)(i)–(iii)	Records related to SSM	Yes.	
§63.10(b)(2)(iv)–(v)	Records related to actions during SSM	Yes.	
§63.10(b)(2)(vi)–(xi)	CMS records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA.	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CMS.	Yes	Except that §63.10(c)(2)–(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart YYYY does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports.	No	Subpart YYYY does not require reporting of startup, shutdowns, or malfunctions.
§63.10(e)(1) and (2)(i)	Additional CMS reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart YYYY does not require COMS.
§63.10(e)(3)	Excess emissions and parameter exceedances reports.	Yes.	

TABLE 7 OF SUBPART YYYY OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART YYYY—Continued

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.10(e)(4)	Reporting COMS data	No	Subpart YYYY does not require COMS.
§63.10(f)	Waiver for recordkeeping and reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

EMISSIONS SUMMARY

The following tables are provided for informational purposes to show the effect of compressor inlet temperature and duct firing on the maximum mass emissions rates. The mass emissions rates were provided in the application for the original air construction permit and represent worst-case potential maximum emissions for the given conditions.

Combined Cycle, Natural Gas Firing - Mass Emissions Rates at 100% Load vs. Compressor Inlet Temperature

Pollutant	Mass Emissions Rates (lb/hour)					
	Combustion Turbine Only			Combustion Turbine w/Duct Burning		
Temperature	25° F	59° F	95° F	25° F	59° F	95° F
CO	41.7	39.1	36.2	96.8	90.3	83.9
NOx [a]	34.3	32.4	30.5	47.8	45.0	42.2
PM/PM_{10}	11.1	11.0	10.9	21.1	20.3	19.6
SO_2	10.5	9.9	9.3	14.7	13.8	13.0
VOC [b]	7.5	7.1	6.7	16.7	15.7	14.7

a. Mass emissions based on a controlled NOx emission level of 5 ppmvd @ 15% oxygen.

b. VOC measured as methane.

Combined Cycle, Distillate Oil Firing - Mass Emissions Rates at 100% Load vs. Compressor Inlet Temperature

Pollutant	Mass Emissions Rates (lb/hour)					
	Combustion Turbine Only			Combustion Turbine w/Duct Burning		
Temperature	25° F	59° F	95° F	25° F	59° F	95° F
CO	87.8	82.2	76.1	142.9	133.4	123.8
NOx [a]	81.4	77.5	72.2	108.4	102.6	95.6
PM/PM_{10}	38.7	37.6	36.2	48.7	47.0	44.9
SO_2	107.0	102.0	95.0	111.0	106.0	99.0
VOC [b]	7.9	7.5	7.0	17.1	16.0	14.9

a. Mass emissions based on a controlled NOx emission level of 10 ppmvd @ 15% oxygen.

b. VOC measured as methane.

Simple Cycle, Natural Gas Firing - Mass Emissions Rates at 100% Load vs. Compressor Inlet Temperature

Pollutant	Mass Emissions Rates (lb/hour)		
	Combustion Turbine Only		
Temperature	25° F	59° F	95° F
CO	41.7	39.1	36.2
NOx [a]	61.8	58.4	55.0
PM/PM_{10}	9.0	9.0	9.0
SO_2	10.5	9.9	9.3
VOC [b]	7.5	7.1	6.7

a. Mass emissions based on a controlled NOx emission level of 9 ppmvd @ 15% oxygen.

b. VOC measured as methane.

P.E. CERTIFICATION STATEMENT

PERMITTEE

City of Tallahassee, Electric Utilities
Arvah B. Hopkins Generating Station
2602 Jackson Bluff Road
Tallahassee, Florida 32304

Draft Air Permit No. 0730003-009-AC
Arvah B. Hopkins Generating Station
Unit 2 Re-Powering Project
Leon County, Florida

PROJECT DESCRIPTION

The applicant proposes to retire the existing boiler for Steam Generating Unit 2 (EU-004) and re-power the Unit 2 steam turbine-electrical generator by installing a new combined cycle unit. The proposed unit will consist of a new combustion turbine and a new heat recovery steam generator (HRSG) with a gas-fired duct burner. The combustion turbine will produce a nominal 188 MW of direct power and the HRSG will re-power the existing Unit 2 steam-electrical generator to produce another 238 MW. The project will not result in an increase in steam-generated electricity. Therefore, only a modification of the site certification is necessary.

NOx emissions from the new combined cycle unit will be controlled by an SCR system to 5 ppmvd @ 15% oxygen (natural gas) and 10 ppmvd @ 15% oxygen (distillate oil). The applicant's PSD netting analysis indicates that there will be no PSD-significant emissions increases for the project to re-power Unit 2. The project results in a minor source air construction permit.

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

Jeffery F. Koerner 8-22-06

Jeffery F. Koerner, P.E. (Date)
Registration Number: 49441

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Robert McGarrah
Manager of Power Production
City of Tallahassee
300 South Adams Street
Tallahassee, Florida 32301

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X V. Brown
☐ Agent
☐ Addressee

B. Received by (*Printed Name*) V Brown

C. Date of Delivery 8/30/06

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

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☒ Certified Mail ☐ Express Mail
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☐ Insured Mail ☐ C.O.D.

☐ Yes

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Manager of Power Production
City of Tallahassee
300 South Adams Street
Tallahassee, Florida 32301

PS Form 3800, May 2000 ... for Instructions

City of Tallahassee
Your Own Utilities℠

00 South Adams Street, Box A-2, Tallahassee, Florida 32301, (850) 891-4YOU (4968), talgov.com

June 6, 2006

Hamilton S. Oven, Administrator
Siting Coordination Office
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Hand Delivered

Re: City of Tallahassee
Arvah B. Hopkins Generating Station
Hopkins Unit 2
Request for Modification of Site Certification
No. PA 74-03

RECEIVED
JUN 07 2006
BUREAU OF AIR REGULATION

Dear Mr. Oven:

Pursuant to Section 403.516, Florida Statutes, the City of Tallahassee (City) hereby requests a modification of the Site Certification for Unit No. 2 at the City's Arvah B. Hopkins Electric Generating Station (Hopkins). By this request, the City is seeking approval to "repower" the existing, certified Hopkins Unit 2 by retiring the existing oil and gas-fired boiler and installing a new combustion turbine and heat recovery steam generator.

The repowering project will not result in an increase in steam electric generating capacity at the Hopkins site. Therefore, a modification of the site certification is necessary. Detailed information regarding the repowering project is provided in the attached application for modification of site certification. The factual reasons supporting the modification and the anticipated effects of the proposed modification on the City, the public and the environment are addressed in this application.

Enclosed, please find a check in the amount of $10,000 made payable to the Department of Environmental Protection as required under Rule 62-17.293(1)(c)2., Florida Administrative Code.

The City requests that the Florida Department of Environmental Protection (Department) undertake a review of this request for modification by consulting with the other affected agencies. Upon conclusion of that review, the City requests that the Department issue a Proposed Order of Modification for review by the parties and the public, and ultimately, a Final Order granting the requested modification of certification.

The City looks forward to working with the Department and the various agencies that will be involved in reviewing this requested modification. Should you have any questions or concerns regarding this modification request, please do not hesitate to contact me at (850) 891-8851, or Rob McGarrah, Manager of Power Production at (850) 891-5534.

Sincerely,

John K. Powell, P.E.
Interim Environmental and Safety Manager

Attachments

cc: Scott Goorland, Esq., FDEP
Parties to Hopkins Unit 2 Certification
FDEP Bureau of Air Regulation (P.E. Sealed Air Permit)

AIR PERMIT APPLICATION FOR THE
CITY OF TALLAHASSEE
ARVAH B. HOPKINS GENERATING STATION
UNIT NO. 2 REPOWERING PROJECT
LEON COUNTY, FLORIDA

Prepared For:
City of Tallahassee
300 South Adams Street
Tallahassee, Florida

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

May 2006
063-7522

DISTRIBUTION:
4 Copies – FDEP
3 Copies – City of Tallahassee
2 Copies – Golder Associates Inc.

APPLICATION FOR AIR PERMIT – LONG FORM

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also use this form to apply for an air construction permit:

- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- Where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- Where the applicant proposes to establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

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

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **City of Tallahassee, Electric Utilities**	
2. Site Name: **Arvah B. Hopkins Generating Station**	
3. Facility Identification Number: **0730003**	
4. Facility Location...: Street Address or Other Locator: **Route 4, Box 450, 1125 Geddie Road (County Road 1585)** City: **Tallahassee** County: **Leon** Zip Code: **32304**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **John K. Powell, J.D., P.E., Environmental Resources**
2. Application Contact Mailing Address... Organization/Firm: **City of Tallahassee, Environmental Resources** Street Address: **City Hall, 300 South Adams Street** City: **Tallahassee** State: **Florida** Zip Code: **32301-1731**
3. Application Contact Telephone Numbers... Telephone: **(850) 891-8851** ext. Fax: **(850) 891-8277**
4. Application Contact Email Address: **powellj@talgov.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 6-9-06	3. PSD Number (if applicable):
2. Project Number(s): 0730003-009-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

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

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

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

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

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

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

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

Application Comment

This application is for repowering of Unit No. 2 with a new GE 7FA combined-cycle combustion turbine (CT). City of Tallahassee proposes to permanently shut down the boiler associated with Unit No. 2 and construct a new GE 7FA CT. The CT can operate in combined cycle mode, with and without a duct burner, and simple cycle mode firing natural gas and distillate fuel oil with exhaust gases routed to the heat recovery steam generator (HRSG) and selective catalytic reduction (SCR) system. The duct burner will be fired with natural gas. In addition, the CT can operate in simple cycle mode firing natural gas only with exhaust gases routed to an emergency bypass stack, instead of the HRSG and SCR system. Emission netting results in pollutant emission increases below the PSD significant thresholds. See Part B.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
CT2A	GE 7FA Combined-Cycle Combustion Turbine and Duct Burner	AC1A	N/A

Application Processing Fee

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

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1. Owner/Authorized Representative Name : **Robert E. McGarrah, Production Superintendent**
2. Owner/Authorized Representative Mailing Address... Organization/Firm: **City of Tallahassee, Electric Utilities** Street Address: **2602 Jackson Bluff Road** City: **Tallahassee** State: **Florida** Zip Code: **32304**
3. Owner/Authorized Representative Telephone Numbers... Telephone: **(850) 891-5534** ext. Fax: **(850) 891-5162**
4. Owner/Authorized Representative Email Address: **McGarraR@talgov.com**
5. Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* RMcGarrah   6/1/06 Signature   Date

APPLICATION INFORMATION

Application Responsible Official Certification

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

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
5. Application Responsible Official Email Address:
6. Application Responsible Official Certification: *I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions.. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.* Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Kennard F. Kosky**
   Registration Number: **14996**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **6241 NW 23rd Street, Suite 500**
   City: **Gainesville** State: **FL** Zip Code: **32653**
3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 336-5600** ext.**516** Fax: **(352) 336-6603**
4. Professional Engineer Email Address: **kkosky@golder.com**
5. Professional Engineer Statement:

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

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

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

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

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

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

Kennard F. Kosky

Signature

5/31/06

Date

(seal)

* Attach any exception to certification statement.

** **Board of Professional Engineers Certificate of Authorization #00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **16** East (km) **749.53** North (km) **3371.7**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **30/27/08** Longitude (DD/MM/SS) **84/24/00**	
3. Governmental Facility Code: **4**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Application Contact Name: **John K. Powell, J.D., P.E., Environmental Resources**
2. Application Contact Mailing Address... Organization/Firm: **City of Tallahassee, Environmental Resources** Street Address: **City Hall, 300 South Adams Street** City: **Tallahassee** State: **Florida** Zip Code: **32301-1731**
3. Application Contact Telephone Numbers... Telephone: **(850) 891-8851** ext. Fax: **(850) 891-8277**
4. Application Contact Email Address: **powellj@talgov.com**

Facility Primary Responsible Official

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

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

Facility Regulatory Classifications

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

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☒ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **NSPS - 40 CFR Part 60, Subpart GG, applies to the proposed turbine and Subpart Da applies to the HRSG duct burner. However, the proposed 40 CFR Part 60, Subpart KKKK, eventually will replace Subpart GG. Under Subpart KKKK, the duct burner would be exempt from meeting the requirements of Subpart Da. NESHAP- 40 CFR Part 63, Subpart YYYY may apply based on actual oil fuel used in a calendar year.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter - PM	**A**	**No**
Particulate Matter with an aerodynamic diameter less than 10 microns - PM_{10}	**A**	**No**
Sulfur Dioxide - SO_2	**A**	**No**
Nitrogen Oxides - NO_x	**A**	**No**
Carbon Monoxide - CO	**A**	**No**
Volatile Organic Compounds - VOCs	**A**	**No**
Total Hazardous Air Pollutants – HAPs	**A**	**No**
Sulfuric Acid Mist – SAM	**A**	**No**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

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

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

Additional Requirements for Air Construction Permit Applications

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

FACILITY INFORMATION

Additional Requirements for FESOP Applications

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

Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:_____ ☒ Not Applicable (revision application)
2.	Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:_____ ☒ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:_____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:_____ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☒ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:_____ ☒ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:_____ ☒ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
   One nominal 188-MW GE 7-FA Combined-Cycle Combustion Turbine with HRSG Duct Firing.

3. Emissions Unit Identification Number: **009**

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

9. Package Unit:
   Manufacturer: **General Electric** Model Number: **7-FA**

10. Generator Nameplate Rating: **188** MW

11. Emissions Unit Comment:
    Based on natural gas-firing at 25°F for CT only. For distillate oil-firing, rating is 199 MW at 25°F.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **025 – Staged Combustion [Dry Low-NO_x (DLN) Burners]** **028 – Water Injection** **139 – Selective Catalytic Reduction (SCR)**	
2. Control Device or Method Code(s): **025, 028, 139**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1.	Maximum Process or Throughput Rate:
2.	Maximum Production Rate: **188 MW (nominal)**
3.	Maximum Heat Input Rate: **2,664** million Btu/hr **(HHV)**
4.	Maximum Incineration Rate: pounds/hr tons/day
5.	Requested Maximum Operating Schedule: hours/day days/week weeks/year **8,760** hours/year
6.	Operating Capacity/Schedule Comment: **Maximum heat input for natural gas-firing at 25 °F, includes 1,899 MMBtu/hr (HHV) heat input from the combustion turbine and 765 MMBtu/hr (HHV) heat input from duct firing. Maximum heat input from oil firing is 2,079 MMBtu/hr (HHV) heat input from the combustion turbine plus 765 MMBtu/hr (HHV) heat input from duct firing natural gas. Heat input varies based on inlet temperature and performance. See Part B.**

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Part B**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **150** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **188** °F	9. Actual Volumetric Flow Rate: **1,016,100** acfm	10. Water Vapor: **11.2** %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **16** East (km): **749.7** North (km): **3371.7**		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)

15. Emission Point Comment:

Information at baseload conditions for natural gas-firing with the duct burner at 59°F ambient temperature. See Part B, Appendix A of the Air Permit Application for performance at various ambient temperatures and loads. The design includes a simple cycle emergency bypass stack with a stack height of 150 feet and a diameter of 18 feet.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engine – Electric Generation; Turbine, Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **2.571**	5. Maximum Annual Rate: **18,323**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,036**
10. Segment Comment: **Maximum hourly rate is for one turbine at 25°F ambient and includes duct firing. Maximum annual rate is based on total of 8,760 hours of operation at 59°F, with 2,598,800 MMBtu/yr of duct firing. See Part B, Appendix A, of the Air Permit Application for performance at various ambient temperatures and loads.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engine – Electric Generation; Turbine, Distillate Oil**		
2. Source Classification Code (SCC): **2-01-001-01.**	3. SCC Units: **1,000 gallons**	
4. Maximum Hourly Rate: **16.0**	5. Maximum Annual Rate: **53,276**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment: **Maximum hourly rate is for one turbine at 25°F ambient and includes maximum duct firing. Maximum annual rate is based on maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours of operation) at 59°F ambient temperature for the CT. See Part B, Appendix A, of the Air Permit Application for performance at various ambient temperatures, loads, and duct firing.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM/PM_{10}			EL
SO_2			EL
NO_x	028	139	EL
CO			EL
VOCs			EL

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

(Optional for unregulated emissions units.)

__Potential/Estimated Fugitive Emissions__

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

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **48.7** lb/hour **111.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **See Part B, Air Permit Application Report.**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **97.5** tons/year	8.b. Baseline 24-month Period: From: **1/1/2004** To: **12/31/2005**
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Maximum hourly rate based on full-load oil firing in CT and duct burner firing gas at 59°F. Annual emissions based on an equivalent 5,260 hours of natural gas firing with maximum heat input rate of 2,598,800 MMBtu/yr for duct firing at full load and maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of the CT at full load and 59°F. Refer to Part B.

11. Pollutant Potential/Estimated Fugitive Emissions Comment:
See Section 2.0 of Part B and Appendix A for performance at various ambient temperatures and loads.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **21.1** lb/hour **65.2** tons/year
5. Method of Compliance: **EPA Method 9; Initial and once annually.**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on natural gas-firing in CT and duct burner at 25°F and full load. Annual emission rate based on natural gas-firing with a maximum heat input rate of 2,598,800 MMBtu/yr of duct firing at 59°F and full load. Refer to Part B.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **38.7** lb/hour **65.8** tons/year
5. Method of Compliance: **EPA Method 9; Initial; Annual, if >400 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on distillate oil-firing in CT at 59°F and full load. Annual emission rate based on maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of CT at 59°F and full load. Refer to Part B.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **111** lb/hour **211.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **See Part B, Air Permit Application Report.**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **1,642** tons/year	8.b. Baseline 24-month Period: From: **2/1/2004** To: **1/31/2006**
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Maximum hourly rate based on full-load oil firing in CT and duct burner firing gas at 25°F. Annual emissions based on an equivalent 5,260 hours of natural gas firing with maximum heat input rate of 2,598,800 MMBtu/yr for duct firing at full load and 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of the CT at full load and 59°F. Refer to Part B.**	
11. Pollutant Potential/Estimated Fugitive Emissions Comment: **See Section 2.0 of Part B and Appendix A for performance at various ambient temperatures and loads.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2 grains S/100 SCF**	4. Equivalent Allowable Emissions: **14.7** lb/hour **50.5** tons/year
5. Method of Compliance: **Fuel analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on natural gas-firing in CT and duct burner at 25°F and full load. Annual emission rate based on natural gas-firing with a maximum heat input rate of 2,598,800 MMBtu/yr of duct firing at 59°F and full load. Refer to Part B.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur**	4. Equivalent Allowable Emissions: **107** lb/hour **178.5** tons/year
5. Method of Compliance: **Fuel analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on distillate oil-firing in CT at 25°F and full load. Annual emission rate based on maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of CT at 59°F and full load. Refer to Part B.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **108.4** lb/hour **265.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **See Part B, Air Permit Application Report.**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **843.3** tons/year	8.b. Baseline 24-month Period: From: **5/1/2003** To: **4/30/2005**
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Maximum hourly rate based on full-load oil firing in CT and duct burner firing gas at 25°F. Annual emissions based on an equivalent 8,760 hours of natural gas firing for simple cycle operation at full load and 59°F with exhaust gases routed to emergency bypass stack. Potential annual emissions for combined cycle operation are based on an equivalent 5,260 hours of natural gas firing with maximum heat input rate of 2,598,800 MMBtu/yr for duct firing at full load and 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing at full load and 59°F. Refer to Part B.**	
11. Pollutant Potential/Estimated Fugitive Emissions Comment: **See Section 2.0 of Part B and Appendix A for performance at various ambient temperatures and loads.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **47.8** lb/hour **164.9** tons/year
5. Method of Compliance: **CEMS 30-day rolling average**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on natural gas-firing in CT and duct burner at 25°F and full load. Annual emission rate based on natural gas-firing with a maximum heat input rate of 2,598,800 MMBtu/yr of duct firing at 59°F and full load. Refer to Part B**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd @ 15% O_2 for CT**	4. Equivalent Allowable Emissions: **108.4** lb/hour **135.6** tons/year
5. Method of Compliance: **CEMS 30-day rolling average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on distillate oil-firing in CT and duct burner(gas) at 25°F and full load. Annual emission rate based on maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of CT at 59°F and full load.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **9 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **61.8** lb/hour **255.6** tons/year
5. Method of Compliance: **CEMS (see Part B)**	
6. Allowable Emissions Comment (Description of Operating Method): **For simple cycle operation with emergency bypass stack. Maximum hourly rate based on natural gas-firing in CT at 25°F and full load. Annual emission rate based on an equivalent 8,760 hours of operation at 59°F and full load. Refer to Part B**	

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **142.9** lb/hour **340.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **See Part B, Air Permit Application Report.**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **241.1** tons/year	8.b. Baseline 24-month Period: From: **1/1/2001** To: **12/31/2002**
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Maximum hourly rate based on full-load oil firing in CT and duct burner firing gas at 25°F. Annual emissions based on an equivalent 5,260 hours of natural gas firing with maximum heat input rate of 2,598,800 MMBtu/yr for duct firing at full load and 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing in the CT burner at full load and 59°F. Refer to Part B.

11. Pollutant Potential/Estimated Fugitive Emissions Comment:
See Section 2.0 of Part B and Appendix A for performance at various ambient temperatures and loads.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **16.8 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **96.8** lb/hour **264.6** tons/year
5. Method of Compliance: **EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on natural gas-firing in CT and duct burner (gas) at 25°F and full load. Annual emission rate based on natural gas-firing with a maximum heat input rate of 2,598,800 MMBtu/yr of duct firing at 59°F and full load. 10 ppmvd at 15% O_2 for CT only. Refer to Part B.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **21.4 ppmvd @ 15% O_2 with duct firing.**	4. Equivalent Allowable Emissions: **142.9** lb/hour **143.9** tons/year
5. Method of Compliance: **EPA Method 10; Initial; Annual >400 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on distillate oil-firing in CT and duct burner (gas) at 25°F and full load. Annual emission rate based on maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of CT at 59°F and full load. 17.7 ppmvd at 15% O_2 for CT only. Refer to Part B.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **VOCs**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17.1** lb/hour **47.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **See Part B, Air Permit Application Report.**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **19.7** tons/year	8.b. Baseline 24-month Period: From: **1/1/2004** To: **12/31/2005**
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Maximum hourly rate based on full-load oil firing in CT and duct burner firing gas at 25°F. Annual emissions based on an equivalent 5,260 hours of natural gas firing with maximum heat input rate of 2,598,800 MMBtu/yr for duct firing at full load and 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing in the CT at full load and 59°F. Refer to Part B.**	
11. Pollutant Potential/Estimated Fugitive Emissions Comment: **See Section 2.0 of Part B and Appendix A for performance at various ambient temperatures and loads.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5.7 ppmvd @ 15% O_2 for CT and HRSG**	4. Equivalent Allowable Emissions: **16.7** lb/hour **46.8** tons/year
5. Method of Compliance: **EPA Method 25A, Initial performance test only.**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on natural gas-firing in CT and duct burner at 25°F and full load. Annual emission rate based on natural gas-firing with a maximum heat input rate of 2,598,800 MMBtu/yr of duct firing at 59°F and full load. 3.2 ppmvd at 15% O_2 for CT only. Refer to Part B.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5.3 ppmvd @ 15% O_2 for CT and DB**	4. Equivalent Allowable Emissions: **17.1** lb/hour **13.1** tons/year
5. Method of Compliance: **EPA Method 25A, Initial performance test only**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum hourly rate based on distillate oil-firing in CT and duct burner (gas) at 25°F and full load. Annual emission rate based on maximum heat input rate of 6,926,500 MMBtu/yr (equivalent to 3,500 hours) of distillate oil-firing of CT at 59°F and full load. Refer to Part B.**	

Allowable Emissions Allowable Emissions ____ of ____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Rule 62-296.320 (4) (b). Excess emissions. Refer to Part B.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **TBD** Model Number: **TBD** Serial Number: **TBD**	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **TBD = To be determined. CEM required pursuant to 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **O_2 or CO_2**	2. Pollutant(s): **Oxygen or Carbon Dioxide**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **TBD** Model Number: **TBD** Serial Number: **TBD**	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Diluent monitor required pursuant to 40 CFR Part 75 for NO_x monitoring.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

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

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

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

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

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

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

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

PART B

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1.0 INTRODUCTION

The City of Tallahassee proposes to repower the Arvah B. Hopkins Generating Station Unit No. 2, located in Leon County, Florida (see Figure 2.1-1 of the Report for the modification to the Site Certification). The repowering of Unit No. 2 will include the addition of one nominal 188-megawatt (MW) combustion turbine and the permanent shut down of the fossil fuel steam generator for Unit 2. The repowering will enhance the City's electric system reliability and help the City meet the current forecasts of growth in population and electric demand.

The Arvah B. Hopkins Generating Station is an existing generating facility presently comprised of two steam electric generating units (Units 1 and 2), two Westinghouse combustion turbines (CTs) (referred to as GT-1 and GT -2), and two General Electric (GE) LM6000 CTs (referred to as GT -3 and GT -4). GT -3 and GT -4 began operation in 2005.

The proposed combined cycle unit will consist of one GE 7FA CT and associated electric generator, heat recovery steam generator (HRSG), and the existing steam turbine-electric generator. The unit will be equipped with a bypass stack that will be used with natural gas firing only. Together, these facilities are referred to as the "Project".

The proposed CT will use dry low-nitrogen oxides [(NO_x) DLN] combustion technology when operating on natural gas and water injection for NO_x control when operating on distillate fuel oil. The CT/HRSG will be installed with selective catalytic reduction (SCR) to further reduce emissions of NO_x. The HRSG will be equipped with duct burners that will fire natural gas.

The CT will operate a maximum of 8,760 hours per year. The CT will operate up to an equivalent of 3,500 hours per year on distillate fuel oil at full-load operating. Existing transmission and fuel supply facilities are adjacent to the proposed location of the new CT.

The Project will be a minor modification to an existing major air pollution source and requires review under the Department's air construction permit rules. Because the Project is being constructed at a certified site under the Florida Power Plant Siting Act (PPSA), a modification to the site certification is also required. The U.S. Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FDEP) have implemented regulations requiring a Prevention of Significant Deterioration (PSD) review for new major sources or major modifications at major sources that increase air emissions above certain threshold amounts. Because the proposed modification will not exceed the major modification threshold amounts, the Project is not subject to PSD review.

Leon County, Florida, has been designated as an attainment or unclassifiable area for all criteria pollutants [i.e., attainment: ozone (O_3); sulfur dioxide (SO_2); carbon monoxide (CO); and nitrogen dioxide (NO_2); unclassifiable: particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) and lead] and is a PSD Class II area for PM_{10}, SO_2, and NO_2. Therefore, the preconstruction minor modification review will follow regulations pertaining to such designations.

The air permit application is divided into three major sections:

- Section 1.0 is an introduction to the Project.
- Section 2.0 presents a description of the Project, including air emissions and stack parameters.
- Section 3.0 provides a review of the regulatory requirements applicable to the Project.

2.0 PROJECT DESCRIPTION

2.1 Site Description

The Arvah B. Hopkins Generating Station consists of approximately 232 acres and is presently comprised of two steam electric generating units (Units 1 and 2), two Westinghouse CTs (GT -1 and GT -2), and two GE LM6000 CTs (GT -3 and GT -4). The steam electric units and the CTs use oil, natural gas, and/or liquefied petroleum gas as fuel. Unit 1, which went into service in 1971, is a nominal 75-MW unit. Unit 2, which went into service in 1977, is a nominal 238-MW unit. The existing CT, HC-1, went into service in 1970 and has a nominal generating capacity of approximately 16.5 MW (nominal). The existing CT, GT -2, went into service in 1972 and has a generating capacity of approximately 25 MW (nominal). The LM6000 CTs, GT-3 and GT-4, use natural gas and distillate fuel oil. Both GT-3 and GT-4 went into service in 2005 and have a total generating capacity of approximately 94 MW (net summer rating).

The plant site is bounded by Geddie Road to the west, CSX railroad to the east, State Road 20 to the south and U.S. Highway 90. The plant elevation will be approximately 136 feet above mean sea level (ft-msl). The terrain surrounding the site is gently rolling hills.

2.2 Unit No. 2 Repowering Project

2.2.1 Shutdown of Existing Unit No. 2 Boiler

The City of Tallahassee proposes to repower existing Unit No. 2 with one combined-cycle CT with a duct burner. The repowering Project will result in the permanent shutdown of the Unit No. 2 boiler and replaced with a new combined cycle unit.

2.2.2 Proposed Unit

The proposed CT will be configured as a combined-cycle unit. The combined cycle unit will consist of one GE Frame 7FA CT with an associated HRSG, and the existing Unit 2 steam turbine-electric generator. The CT will use DLN combustion technology when firing natural gas and water injection when firing light oil to minimize NO_x formation. SCR will be installed in the HRSG to further reduce emissions of NO_x. The unit may operate in simple cycle mode; however, the exhaust gases will be routed through the HRSG and SCR system, with the same emissions achieved as those for the combined cycle mode. Natural gas and light oil will be used an alternative fuels.

In the event of a major unplanned forced outage of the HRSG or to the steam turbine, the electrical output associated with the CT would not be available to meet system reliability needs without an alternative to routing steam through the HRSG. To mitigate the system reliability impacts from such a major unplanned forced outage event, an emergency HRSG bypass system be installed as a part of the Project. The bypass stack would be physically inoperable during combined cycle operations. To utilize the bypass stack, the unit would have to be removed from service, a "blanking plate" in the duct would have to be physically removed, and a HRSG blanking plate would have to be installed. Since this would be for emergency bypass use only, the bypass stack would not be equipped with a SCR. During these emergency situations, the City would propose that the unit operate on natural gas only. Compliance with this mode of operation would be demonstrated using the NO_x CEMs without the SCR operating.

Plant performance for the GE 7FA CT was developed for natural gas and oil at 100-, 75-, and 60-percent load and 25, 59, and 95 degrees Fahrenheit (°F) ambient dry bulb temperatures, respectively. Nominal part load percentages herein are relative to 100-percent load without evaporative cooling.

For the CT, the maximum heat input is 1,899 MMBtu/hr (HHV) or 1,711 MMBtu/hr (LHV) when firing natural gas (100-percent capacity, 25°F). For fuel oil firing, the maximum heat input is 2,079 MMBtu/hr (HHV) or 1,961 MMBtu/hr (LHV) (100-percent capacity, 25°F).

The HRSG will be equipped with a duct burner with a maximum heat input of 712 MMBtu/hr (HHV) when firing natural gas at 59 °F. The duct burner has a maximum heat input of 765 MMBtu/hr (HHV) when firing natural gas at 25°F.

The CT will use DLN combustion technology (when firing natural gas) and water injection (when firing distillate oil) to minimize NO_x formation. SCR will be installed in the HRSG to further reduce emissions of NO_x.

The SO_2 emissions will be controlled by the use of low-sulfur fuels. Good combustion practices and clean fuels will also minimize potential emissions of PM, CO, volatile organic compounds (VOC), and other pollutants (e.g., trace metals).

SCR reactors for the unit will be located in the HRSG to provide the proper operating temperature range for the required reaction between ammonia and NOx to achieve the proposed emission rate and to assure the economical operation of the system. The NO_x is reduced by a chemical reaction with the ammonia in the presence of the catalyst. Ammonia is carried by a diluent and injected into the exhaust gas upstream of the catalyst modules. The ammonia reacts with NO_x on the surface of the catalyst to form nitrogen and water.

Natural gas is currently available at the Hopkins facility. As such, there will be minimal additional infrastructure required to support additional natural gas delivery to the site. The Hopkins facility currently has two existing 10,000 bbl diesel storage tanks and two #6 fuel oil tanks (55,000 bbl and 180,000 bbl). The City plans on converting the 180,000 bbl tank to diesel storage. The existing diesel storage tanks and the converted #6 fuel oil tank will be used for the Project, and no new fuel oil tanks will be required.

2.3 Proposed Source Emissions and Stack Parameters

2.3.1 Shutdown of Existing Unit No. 2

The permanent shutdown of the Unit No. 2 boiler will result in emission reductions. These emission reductions are used in the netting analysis for determination of PSD applicability of the Project (see Section 3.0).

To determine the baseline past actual emissions for the existing Unit No. 2, the highest emissions over a consecutive 24-month period in the last 5 years were utilized. This analysis was conducted on a pollutant-by-pollutant basis and is presented in Tables 2-1 through 2-3. The PM/PM_{10}, CO, VOC, and lead emissions are presented in Table 2-1 and are based on fuel usage from the annual operating reports (AORs) reported to the FDEP and the latest AP-42 emission factors for natural gas and fuel oil combustion. These data are presented from 2001 to 2005 and are based on annual emissions estimated for each calendar year. The SO_2 and NO_x emissions are presented in Tables 2-2 and 2-3, respectively, and are based on data recorded by the continuous emission monitor system (CEMS). These data are presented on a monthly basis from March 2001 to February 2006 since the CEMS data are available monthly.

For PM/PM_{10}, VOC, lead, and mercury emissions, the highest annual average emissions occurred over the 24-month period from 2004 to 2005. For CO emissions, the highest annual average emissions occurred over the 24-month period from 2001 to 2002. For SO_2 emissions, the highest annual average emissions from the CEM data occurred over the 24-month period from February 2004 to January 2006. For NO_x emissions, the highest annual average emissions from the CEM data occurred over the 24-month period from May 2003 to April 2005. The annual average emission rates for those years were used to represent the actual annual average emissions for those pollutants.

2.3.2 Proposed Unit

The maximum estimated hourly emission rates of regulated pollutants for combined cycle operation for the CT/HRSG with and without the duct burner when firing natural gas and distillate oil at baseload conditions are presented in Tables 2-4 and 2-5, respectively. The maximum estimated hourly emission rates when the CT is firing distillate oil and the duct burner is firing natural gas are also presented in Table 2-5. The same emission rates will be achieved during simple cycle operation when the exhaust gases are routed through the HRSG and SCR system. The maximum estimated hourly emission rates of regulated pollutants for simple cycle operation when the exhaust gases are routed through the emergency bypass stack, instead of the HRSG and SCR system, are presented in Table 2-6. Only natural gas will be fired when the emergency bypass stack is used. The primary pollutants emitted by the CT/HRSG will be NO_x, CO, SO_2, PM, and VOC.

The maximum estimated hourly emission rates and exhaust information representative of the CT/HRSG and duct burner were determined using the manufacturer's information for the equipment proposed for the Project. The design parameters were provided for operating loads of 100- (baseload), 75-, and 60-percent capacity and for ambient temperatures of 25, 59, and 95°F, respectively. The performance and emissions data for the operating conditions are given in Appendix A for turbine inlet temperatures of 25, 59, and 95°F and various operating conditions (100-percent load and low-load operation applicable for the CT).

As shown in Tables 2-4 through 2-6, the maximum short-term emission rates [pounds per hour (lb/hr)] for base load conditions occur at 25°F operations when the CT has the greatest output and greatest fuel consumption.

The maximum potential annual emissions for the repowered unit are presented in Table 2-7. Annual emissions were based on emissions expected for baseload and ambient temperatures of 59°F. The maximum annual emissions are based on the range of operations that could occur with operating the CT on natural gas and distillate oil and the CT, operating with the duct burners firing natural gas. In addition, the maximum annual emissions were estimated for the CT operating in simple cycle mode with the exhaust to an emergency bypass stack (bypass stack would not be equipped with a SCR).

The annual operation of the repowered unit will be limited so that the net emission increase of all pollutants will be less than the PSD significant emission rates. The allowable annual operation was determined from an analysis of the emissions for various operating scenarios. These scenarios are reflected in the range of operating hours and fuels (natural gas and distillate oil) shown in Table 2-7 for CT operating alone and the CT operating with maximum duct firing. The operating envelope being proposed consists of four parts that are discussed below:

1. CT operation mode when firing natural gas in combined cycle or simple cycle mode with the exhaust gases routed through the HRSG and SCR system is not limited (see Operating Scenarios A and E in Table 2-7). CT operation in simple cycle mode with the emergency bypass stack will be limited to natural gas firing. The emissions during this operational mode are not higher than those in the combined cycle mode for any pollutant except for NO_x. NO_x emissions in this mode are not limiting based on the netting analysis described in Section 3.0 and shown as Operating Scenario E in Table 2-7.
2. Duct firing with natural gas is proposed to be limited to 2,598,800 MMBtu/yr (HHV), which is equivalent to 3,650 hours at the maximum duct firing rate of 712 MMBtu/hr (see Operating Scenario B).
3. The maximum amount of distillate oil firing in the CT is proposed to be limited to 6,926,500 MMBtu/yr, which is equivalent to 3,500 hours at full load as shown in Table 2-7 as Operating Scenarios C and D.

The potential annual emissions are based on the 59°F turbine inlet temperature at 100-percent load condition, which is conservative since the annual average temperatures for the Tallahassee area are slightly higher than 70°F. Higher turbine inlet temperatures result in lower turbine performance and lower mass emissions. The conservative nature of the turbine inlet temperature combined with a 100-percent capacity factor (i.e., 8,760 hours per year at full load) result in worst-case emissions estimates.

Emission factors for hazardous air pollutants (HAPs) were evaluated based on the revised AP-42 emission factors, the EPA Combustion Turbine Emissions Database, and the CT Maximum Achievable Control Technology (MACT) standards. The HAP emissions are based on emission factors from the April 2000 revision of EPA's AP-42 emission factors for large stationary CTs. Summaries of the emission factors and emissions for light oil-firing and gas-firing are presented in Appendix A.

The MACT standard in 40 CFR, Subpart YYYY, is potentially applicable to the Project. The HAPs emissions from the Project will be less than 10 tons per year (TPY) for any single HAP and less than 25 TPY for all HAPs. However, the Hopkins Plant is a major source of HAP emissions since emissions exceed 10 TPY of a single HAP and exceed 25 TPY for all HAPs and will remain a major source of HAPs after the repowering project. Since low-sulfur light oil is proposed to be fired in the proposed CT, the proposed CT is defined as "stationary diffusion flame oil-fired combustion turbines" under the Subpart YYYY requirements. The Project, combined with two other CTs at the Hopkins facility, would have the potential for an aggregate total potential of 1,000 hours or more of oil firing during any calendar year. Actual applicability of Subpart YYYY is based on actual oil fuel used in a calendar year. The proposed Project will be required to demonstrate compliance with the CT MACT of 91-parts per billion by volume, dry (ppbvd) formaldehyde, corrected to 15-percent oxygen, if the aggregate 1,000 hours per year is exceeded. Based on the applicability of Subpart YYYY, compliance will be determined upon initial operation and annually (40 CFR Part 63, Section 63.6120, Table 3).

An emission factor for toluene of 33 pounds (lb)/10^{12} British thermal units (Btu) for natural gas firing, was developed from the data in the EPA Combustion Turbine Emissions Database. This factor is based on the median value for loads greater than 80 percent. Similar to formaldehyde emission factors, there are no confirmed test data of toluene emissions from F Class turbines. The recent EPA emission factor, which is based on much smaller turbines than those proposed for the Project, suggests toluene emissions from gas turbines of 130 lb/10^{12} Btu when firing natural gas at loads greater than 80 percent. For all loads, the average and median EPA factors are 94 and 19 lb/10^{12} Btu, respectively. Since the median emission factor is about 4 to 5 times lower than the average factor, this clearly points to the large range in toluene emissions and how the individual CT characteristics can influence the results.

The emission factors for many of the other HAPs were developed by EPA in a manner similar to toluene. For these HAPs, fewer data are available and are also considered not representative of state-of-the-art DLN combustion systems. The use of AP-42 emission factors for HAPs is considered to provide conservative estimates of emissions.

The GE 7FA CT with SCR will experience excess emissions during the short startup and shutdown periods for NO_x and may experience excess emissions for other pollutants. The conservative turbine inlet temperature combined with the assumption of 100-percent capacity factor provides maximum potential emissions that would envelope operation including any excess emissions from startups and shutdowns.

2.4 Site Layout, Structures, and Stack Sampling Facilities

A site plan of the proposed Project is presented in Figure 2.1-2 (see the Report for the modification to the Site Certification) and a process flow diagram is presented in Figure 2-1. Stack sampling facilities will be constructed in accordance to Rule 62-297.310(6), F.A.C.

TABLE 2-1
ESTIMATED ACTUAL ANNUAL PM/PM_{10}, CO, VOC, LEAD, AND MERCURY EMISSIONS
FOR THE EXISITNG HOPKINS UNIT 2 WITH LATEST AP-42 EMISSION FACTORS

Pollutant	Units	Emissions 2001	2002	2003	2004	2005	Maximum 2-year Period
Total Emissions							
PM	TPY	32.2	26.3	111.1	126.2	146.5	136.3
PM_{10}	TPY	24.3	20.2	79.2	90.4	104.7	97.5
CO	TPY	233.8	248.4	181.2	252.8	194.1	241.1
VOC	TPY	16.3	17.0	16.6	21.7	17.7	19.7
Lead	TPY	0.0046	0.0040	0.017	0.019	0.018	0.019
Mercury	TPY	0.00032	0.00026	0.00127	0.00140	0.00135	0.0014
Residual Oil (Grade 6)[a]							
PM	TPY	27.2	20.9	108.2	121.8	143.4	
PM_{10}	TPY	19.3	14.8	76.4	86.0	101.6	
CO	TPY	11.0	8.4	54.5	59.1	57.8	
VOC	TPY	1.7	1.3	8.3	9.0	8.8	
Lead	TPY	0.0033	0.0025	0.016	0.018	0.017	
Mercury	TPY	0.00025	0.00019	0.00123	0.00134	0.00131	
S content	percent	1	1	0.73	0.77	1	
Fuel usage	1,000 gal/yr	4,383.20	3,367.20	21,799.08	23,658.40	23,109.50	
Natural Gas[b]							
PM	TPY	5.0	5.4	2.9	4.4	3.1	
PM_{10}	TPY	5.0	5.4	2.9	4.4	3.1	
CO	TPY	222.9	239.9	126.7	193.7	136.3	
VOC	TPY	14.6	15.7	8.3	12.7	8.9	
Lead	TPY	0.0013	0.0014	0.0008	0.0012	0.0008	
Mercury	TPY	0.00007	0.00007	0.00004	0.00006	0.00004	
Fuel usage	million cubic ft/yr	5,306.81	5,712.80	3,016.04	4,611.60	3,245.20	

[a] Emission factors for residual fuel oil (AP-42, Section 1.3, 9/98)

PM	lb/1,000 gal	(9.19 x S) + 3.22	(Filterable only)
PM_{10}	lb/1,000 gal	5.9 x [(1.12 x S) + 0.37]	(Filterable only)
CO	lb/1,000 gal	5.0	
VOC	lb/1,000 gal	0.76	
Lead	lb/1,000 gal	0.00151	
Mercury	lb/1,000 gal	0.000113	

[b] Emission factors for natural gas (AP-42, Section 1.4, 3/98)

PM	lb/mmcf	1.9	(Filterable only)
PM_{10}	lb/mmcf	1.9	(Filterable only)
CO	lb/mmcf	84	
VOC	lb/mmcf	5.5	
Lead	lb/mmcf	0.0005	
Mercury	lb/mmcf	0.000026	

TABLE 2-2
ACTUAL SO_2 EMISSIONS FOR THE EXISTING HOPKINS UNIT 2
BASED ON CEMS DATA

		SO_2 Emissions			
		Tons/month (TPM)			Tons/year (TPY) Average 24 months Consecutive
Year	Month	Oil	Gas	TOTAL	
Maximum				438	1642
2001	Mar	0	0	0	NA
	Apr	0	0.06	0.06	NA
	May	0	0.28	0.28	NA
	Jun	0	0.27	0.27	NA
	Jul	0	0.31	0.31	NA
	Aug	15.93	0.28	16.21	NA
	Sep	13.64	0.23	13.87	NA
	Oct	0	0	0	NA
	Nov	0	0	0	NA
	Dec	0	0.03	0.03	NA
2002	Jan	36.95	0.07	37.02	NA
	Feb	0	0	0	NA
	Mar	0	0.03	0.03	NA
	Apr	0	0.22	0.22	NA
	May	87.61	0.13	87.74	NA
	Jun	4.42	0.22	4.64	NA
	Jul	0	0.26	0.26	NA
	Aug	0	0.26	0.26	NA
	Sep	4.9	0.2	5.1	NA
	Oct	51.44	0.07	51.51	NA
	Nov	24.64	0.17	24.81	NA
	Dec	0	0.18	0.18	NA
2003	Jan	90.14	0.07	90.21	NA
	Feb	2.31	0.01	2.32	168
	Mar	84.51	0.11	84.62	210
	Apr	0	0.03	0.03	210
	May	189.66	0.08	189.74	305
	Jun	181.58	0.09	181.67	395
	Jul	183.92	0.1	184.02	487
	Aug	212.51	0.08	212.59	585
	Sep	112.8	0.14	112.94	635
	Oct	59.11	0.2	59.31	665
	Nov	0	0.01	0.01	665
	Dec	194.67	0.02	194.69	762
2004	Jan	135.3	0.04	135.34	811
	Feb	70.44	0.16	70.6	846
	Mar	84.04	0.17	84.21	889
	Apr	66.43	0.17	66.6	922
	May	123.79	0.19	123.98	940
	Jun	134.84	0.16	135	1005
	Jul	155.65	0.12	155.77	1083
	Aug	170.1	0.11	170.21	1168
	Sep	183.31	0.08	183.39	1257
	Oct	194.54	0.09	194.63	1328
	Nov	44.04	0.08	44.12	1338
	Dec	128.77	0.03	128.8	1402
2005	Jan	115.66	0.02	115.68	1415
	Feb	150.79	0.01	150.8	1489
	Mar	29.15	0.01	29.16	1462
	Apr	265.29	0	265.29	1594
	May	12.7	0.21	12.91	1506
	Jun	34.93	0.18	35.11	1433
	Jul	101.54	0.18	101.72	1391
	Aug	276.69	0.09	276.78	1424
	Sep	103.71	0.14	103.85	1419
	Oct	-	-	97.0	1438
	Nov	-	-	29.7	1453
	Dec	-	-	438.4	1575
2006	Jan	-	-	270.2	1642
	Feb	-	-	14.2	1614

TABLE 2-3
ACTUAL NO_x EMISSIONS FOR THE EXISTING HOPKINS UNIT 2
BASED ON CEMS DATA

Year	Month	NO_x Emissions Tons/month (TPM) TOTAL	NO_x Emissions Tons/year (TPY) Average 24 months Consecutive
Maximum		131	843
	Mar	0.00	NA
	Apr	22.43	NA
	May	91.98	NA
	Jun	83.45	NA
	Jul	99.49	NA
	Aug	131.33	NA
	Sep	70.79	NA
	Oct	0.93	NA
	Nov	0.00	NA
	Dec	7.62	NA
2002	Jan	36.00	NA
	Feb	0.00	NA
	Mar	11.55	NA
	Apr	99.18	NA
	May	71.81	NA
	Jun	56.04	NA
	Jul	73.79	NA
	Aug	75.77	NA
	Sep	60.50	NA
	Oct	39.19	NA
	Nov	45.23	NA
	Dec	30.12	NA
2003	Jan	52.94	NA
	Feb	3.40	582
	Mar	52.18	608
	Apr	3.72	599
	May	76.00	591
	Jun	96.32	597
	Jul	88.72	592
	Aug	99.95	576
	Sep	79.38	580
	Oct	72.05	616
	Nov	1.31	616
	Dec	81.19	653
2004	Jan	60.74	666
	Feb	60.16	696
	Mar	79.11	729
	Apr	78.72	719
	May	124.15	745
	Jun	101.11	768
	Jul	79.76	771
	Aug	79.86	773
	Sep	85.54	785
	Oct	95.74	814
	Nov	24.06	803
	Dec	44.57	810
2005	Jan	48.36	808
	Feb	47.05	830
	Mar	10.67	809
	Apr	72.16	843
	May	44.70	828
	Jun	46.56	803
	Jul	81.39	799
	Aug	114.19	806
	Sep	46.85	790
	Oct	2.07	755
	Nov	0.61	755
	Dec	14.10	721
2006	Jan	1.32	691
	Feb	0.67	662

TABLE 2-4
STACK, OPERATING, AND EMISSION DATA FOR THE PROPOSED HOPKINS UNIT 2 REPOWERING PROJECT FOR NATURAL GAS-FIRING FOR BASELOAD COMBINED CYCLE OPERATIONS

		Natural Gas-Firing[a]					
		CT Only			CT with Duct Burner on Gas		
Parameter	Units	25 °F	59 °F	95 °F	25 °F	59 °F	95 °F
Combustion Turbine Performance							
Net power output (MW)	MW	187.8	174.4	160.3	187.8	174.4	160.3
Net heat rate	Btu/kWh, LHV	9,110	9,270	9,495	9,110	9,270	9,495
	Btu/kWh, HHV	10,112	10,290	10,539	10,112	10,290	10,539
Heat Input	MMBtu/hr, LHV	1,711	1,617	1,522	1,711	1,617	1,522
	MMBtu/hr, HHV	1,899	1,795	1,689	1,899	1,795	1,689
Relative Humidity	%	87	78	50	87	78	50
Fuel heating value	Btu/lb, LHV	20,714	20,714	20,714	20,714	20,714	20,714
	Btu/lb, HHV	22,993	22,993	22,993	22,993	22,993	22,993
Duct Burner							
Heat Input	MMBtu/hr, LHV	0.0	0.0	0.0	765	712	663
	MMBtu/hr, HHV	0.0	0.0	0.0	689	641	597
CT/HRSG Stack Data							
Height	ft	150	150	150	150	150	150
Diameter	ft	18	18	18	18	18	18
100 Percent Load							
Temperature (°F)	°F	203	202	201	189	188	190
Velocity (ft/sec)	ft/sec	70.9	67.0	63.2	70.4	66.5	63.0
Maximum Hourly Emissions							
SO_2	lb/hr	10.47	9.90	9.32	14.7	13.8	13.0
PM/PM_{10}	lb/hr	11.1	11.0	10.9	21.1	20.3	19.6
NO_x	lb/hr	34.3	32.4	30.5	47.8	45.0	42.2
	ppmvd @ 15% O_2	5	5	5	5	5	5
CO	lb/hr	41.7	39.1	36.2	96.8	90.3	83.9
	ppmvd	12.0	12.0	12.0	28.6	28.5	28.6
	ppmvd @ 15% O_2	10.0	9.9	9.7	16.8	16.7	16.5
VOC (as methane)	lb/hr	7.52	7.12	6.72	16.70	15.66	14.67
	ppmvw	3.50	3.50	3.50	8.64	8.66	8.76
	ppmvd @ 15% O_2	3.15	3.16	3.16	5.67	5.71	5.80
Lead	lb/hr	NA	NA	NA	NA	NA	NA
Sulfuric Acid Mist	lb/hr	1.05	0.99	0.93	1.89	1.77	1.66

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.
Includes simple cycle operation with exhaust gases routed to the HRSG and SCR system.

Source: GE, 2006.

TABLE 2-5
STACK, OPERATING, AND EMISSION DATA FOR THE PROPOSED HOPKINS UNIT 2 REPOWERING PROJECT FOR DISTILLATE OIL-FIRING FOR BASELOAD COMBINED CYCLE OPERATIONS WITH NATURAL GAS DUCT FIRING

		Distillate Oil-Firing [a]					
		CT Only			CT with Duct Burner on Gas		
Parameter	Units	25 °F	59 °F	95 °F	25 °F	59 °F	95 °F
Combustion Turbine Performance							
Power output (MW)	MW	198.9	187.9	172.4	198.9	187.9	172.4
Heat rate	Btu/kWh, LHV	9,860	9,935	10,090	9,860	9,935	10,090
	Btu/kWh, HHV	10,452	10,531	10,695	10,452	10,531	10,695
Heat Input	MMBtu/hr, LHV	1,961	1,867	1,740	1,961	1,867	1,740
	MMBtu/hr, HHV	2,079	1,979	1,844	2,079	1,979	1,844
Relative Humidity	%	87	78	50	87	78	50
Fuel heating value	Btu/lb, LHV	18,300	18,300	18,300	18,300	18,300	18,300
	Btu/lb, HHV	19,398	19,398	19,398	19,398	19,398	19,398
Duct Burner							
Heat Input	MMBtu/hr, LHV	0.0	0.0	0.0	765	712	663
	MMBtu/hr, HHV	0.0	0.0	0.0	689	641	597
CT/HRSG Stack Data							
Height	ft	150	150	150	150	150	150
Diameter	ft	18	18	18	18	18	18
100 Percent Load							
Temperature (oF)	°F	248	248	247	206	204	201
Velocity (ft/sec)	ft/sec	79.5	75.1	70.3	75.8	71.4	66.6
Maximum Hourly Emissions							
SO_2	lb/hr	107	102	95	111	106	99
PM/PM_{10}	lb/hr	38.7	37.6	36.2	48.7	47.0	44.9
NOx	lb/hr	81.4	77.5	72.2	108.4	102.6	95.6
	ppmvd @ 15% O2	10.0	10.0	10.0	10.0	10.0	10.0
CO	lb/hr	87.8	82.2	76.1	142.9	133.4	123.8
	ppmvd	25.0	25.0	25.0	41.9	41.8	41.9
	ppmvd @ 15% O2	17.7	17.4	17.3	21.4	21.2	21.1
VOC (as methane)	lb/hr	7.89	7.46	6.99	17.1	16.0	14.9
	ppmvw	3.5	3.5	3.5	7.6	7.5	7.5
	ppmvd @ 15% O2	2.8	2.8	2.8	5.2	5.2	5.3
Lead	lb/hr	0.029	0.028	0.026	0.029	0.028	0.026
Sulfuric Acid Mist	lb/hr	21.4	20.4	19.0	22.3	21.2	19.7

[a] Refer to Air Construction Permit Application (Appendix 10.1.5) for detailed information on basis of pollutant emission rates and operating data. Includes simple cycle operation with exhaust gases routed to the HRSG and SCR system.

Source: GE, 2006

TABLE 2-6
STACK, OPERATING, AND EMISSION DATA FOR THE PROPOSED HOPKINS UNIT 2 REPOWERING PROJECT FOR NATURAL GAS-FIRING FOR BASELOAD SIMPLE CYCLE OPERATIONS

Parameter	Units	Natural Gas-Firing[a] CT Only 25 °F	59 °F	95 °F
Combustion Turbine Performance				
Net power output (MW)	MW	187.8	174.4	160.3
Net heat rate	Btu/kWh, LHV	9,110	9,270	9,495
	Btu/kWh, HHV	10,112	10,290	10,539
Heat Input	MMBtu/hr, LHV	1,711	1,617	1,522
	MMBtu/hr, HHV	1,899	1,795	1,689
Relative Humidity	%	87	78	50
Fuel heating value	Btu/lb, LHV	20,714	20,714	20,714
	Btu/lb, HHV	22,993	22,993	22,993
CT/Bypass Stack Data				
Height	ft	150	150	150
Diameter	ft	18	18	18
100 Percent Load				
Temperature (°F)	°F	1,081	1,114	1,144
Velocity (ft/sec)	ft/sec	164.9	159.4	153.3
Maximum Hourly Emissions				
SO_2	lb/hr	10.5	9.90	9.32
PM/PM_{10}	lb/hr	9.0	9.0	9.0
NO_x	lb/hr	61.8	58.4	55.0
	ppmvd @ 15% O2	9.0	9.0	9.0
CO	lb/hr	41.7	39.1	36.2
	ppmvd	12.0	12.0	12.0
	ppmvd @ 15% O2	10.0	9.9	9.7
VOC (as methane)	lb/hr	7.52	7.12	6.72
	ppmvw	3.50	3.50	3.50
	ppmvd @ 15% O2	3.15	3.16	3.16
Lead	lb/hr	NA	NA	NA
Sulfuric Acid Mist	lb/hr	1.05	0.99	0.93

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Source: GE, 2006.

TABLE 2-7
SUMMARY OF MAXIMUM POTENTIAL ANNUAL EMISSIONS
FOR THE PROPOSED HOPKINS UNIT 2 REPOWERING PROJECT

Pollutant	Maximum Potential Annual Emissions (TPY) for CT and Duct Burner Operating Scenarios [a]				
	A	B	C	D	E
SO_2	43	51	211.7	211.7	43.4
PM	48	65	111.8	111.8	39.4
PM_{10}	48	65	111.8	111.8	39.4
NO_x	142	165	244	266	256
CO	171	265	340	340	171
VOC (as methane)	31.2	46.8	47.4	47.4	31.2
Sulfuric Acid Mist	4.3	5.8	39.7	39.7	4.3
Lead	0.00E+00	0.00E+00	4.85E-02	4.85E-02	0.00E+00
Mercury	0.00E+00	0.00E+00	4.16E-03	4.16E-03	0.00E+00

[a] Based on the following hours of operation for each operating scenario:

	A	B	C	D	E
Combined Cycle Operation					
CT, natural gas-firing	8,760	5,110	1,610	5,110	0
CT and duct burner, natural gas-firing	0	3,650	3,650	150	0
CT, fuel oil-firing	0	0	3,500	0	0
CT, fuel oil-firing; duct burner, natural gas-firin;	0	0	0	3,500	0
Simple Cycle Operation					
CT, natural gas-firing	0	0	0	0	8,760

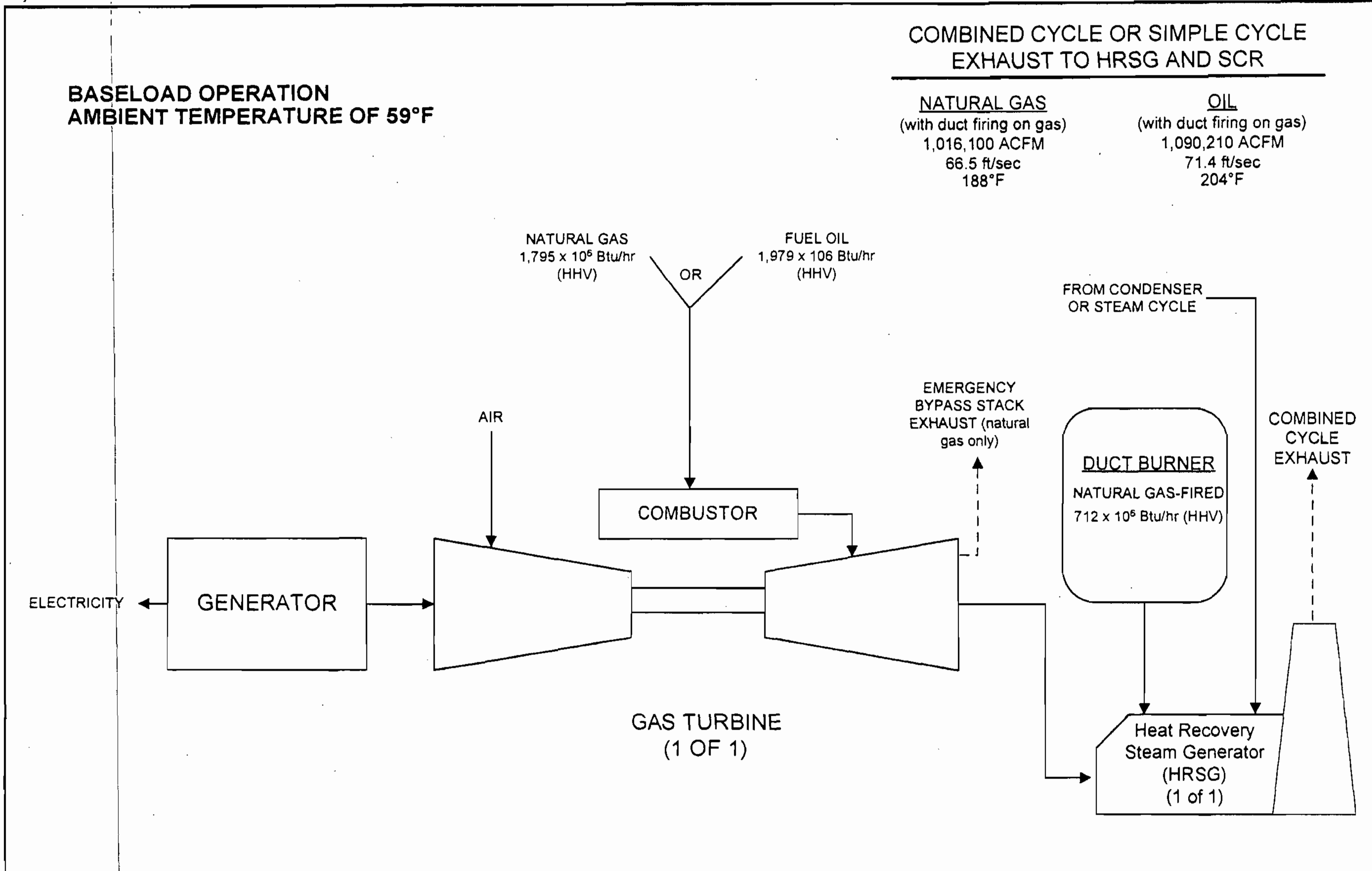

Figure 2-1
Process Flow Diagram
Baseload Operation, Ambient Temperature of 59°F
Unit No. 2 Repowering Project
0637522/4.4/Figure 2-1.vsd

Process Flow Legend
Solid/Liquid →
Gas - - - →

CITY OF TALLAHASSEE

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal, State, and local air regulatory requirements and their applicability to the Hopkins Unit 2 Repowering Project. These requirements must be satisfied before the proposed facility can begin operation.

3.1 National and State Aaqs

The existing applicable national and State of Florida local AAQS are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health with an adequate margin of safety, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in compliance with AAQS are designated as attainment areas. New sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 New Source Review Requirements

3.2.1 General Requirements

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed, and a pre-construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA; therefore, PSD approval authority has been granted to FDEP.

A "major facility" is defined as any one of 28 named source categories that have the potential to emit 100 TPY or more or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. The State of Florida's PSD regulations are found in Rule 62-212.400, F.A.C. Major new facilities are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts (see Table 3-2):

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility also must be reviewed with respect to GEP stack height regulations.

For new minor sources or minor modification made at a major source, the new source review requirements under the PSD regulations do not apply. Instead, an air construction permit must be obtained under the general preconstruction review requirements in Rule 62-212.300, F.A.C., and for units added at a certified site for which conditions of certification are issued under the Power Plant Siting Act.

EPA has promulgated regulations providing that certain increases above an air quality baseline concentration level of SO_2, PM_{10}, and NO_2 concentrations that would constitute significant deterioration. The EPA class designations and allowable PSD increments are presented in Table 3-1. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2.

Because this Project will be a minor modification at a major source, the new source review requirements under the PSD regulations do not apply. As a result, the Project will not be required to undergo PSD review. The Project is still obligated to comply with FDEP regulations in submitting an air construction permit application.

3.2.2 Nonattainment Rules

FDEP has nonattainment provisions (Rule 62-212.500, F.A.C.) that apply to all major new sources facilities located in a nonattainment area. In addition, for major facilities that are located in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The Hopkins Plant is located in Leon County, which is classified as an attainment or unclassifiable area for all criteria pollutants. Therefore, nonattainment new source review requirements are not applicable.

3.3 Emission Standards

3.3.1 New Source Performance Standards

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the 1977 CAA Amendments, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

The Hopkins Unit 2 Repowering Project will be subject to one or more NSPS. The following sections describe NSPS potentially applicable to the project.

Combustion Turbine

The existing applicable federal New Source Performance Standards (NSPS) for the combustion turbine are those promulgated by EPA for stationary gas turbines. These NSPS (40 CFR Part 60, Subpart GG) establish emission-limiting standards for NO_x and SO_2. The applicable NSPS are:

- NO_x - 75 ppmvd corrected to 15-percent O_2 and heat rate plus adjustment to fuel-bound nitrogen, and
- SO_2 - no more than 0.8-percent sulfur in the fuel.

However, on February 18, 2005, EPA proposed new NSPS for Stationary Combustion Turbines that will commence construction after February 18, 2005. These NSPS, Subpart KKKK, eventually will replace Subpart GG and Da for combustion turbines in combined cycle mode with duct burners. When finalized, the Subpart KKKK requirements will supersede the Subpart GG requirements and apply to units with a gross capacity of greater than 1 MW. The proposed Subpart KKKK requirements that would apply to the Project when finalized by EPA are applicable to combustion turbines greater than 30 MW. The NOx emissions are limited to 0.39 lb/MW-hr for gas-firing and 1.2 lb/MW-hr for light oil firing. Based on a typical simple cycle CT efficiency, these emission rates are approximately equivalent to 10 ppmvd corrected to 15-percent O_2 when firing natural gas and 30 ppmvd corrected to 15-percent O2 when firing light oil. For SO_2 emissions, the proposed Subpart KKKK requirements limit emissions to 0.58 lb/MW-hr or a fuel sulfur content of 0.05 percent. There are no emission limits in Subpart KKKK for particulate matter.

Duct Burner

The applicable federal NSPS for the duct burner are those promulgated by EPA on February 27, 2006 under 40 CFR Part 60, Subpart Da, for electric utility steam generating units capable of combusting more than 250 MMBtu/hr of fossil fuel for which construction is commenced after September 18, 1978. EPA finalized new NSPS for these units that establish emission-limiting standards for PM, NO_x and SO_2 (PM- 0.015 lb/MMBtu; NO_x- 1.0 lb/MW-hr; SO_2- 1.4 lb/MW-hr; regardless of the type of fuel burned). However, HRSG and duct burners subject to the proposed NSPS, Subpart KKKK, would be exempt from the requirements of NSPS, Subpart Da.

3.3.2 National Emission Standards for Hazardous Air Pollutants

As discussed in Section 2.3, EPA has promulgated MACT standards for combustion turbines. The MACT standard limits formaldehyde emissions to 91 ppbvd corrected to 15-percent O_2, which is equivalent to about 220 lb/10^{12} Btu when firing natural gas and about 240 lb/10^{12} Btu when firing light oil (see Appendix A). The MACT standard could potentially apply to the Project, if during any calendar year oil use exceeds an aggregate of 1,000 hours for all turbines on the site.

3.3.3 Florida Rules

The FDEP has adopted the EPA NSPS by reference in Rule 62-204.800(8): Subsection (b)39 for stationary gas turbines and Subsection (b)2 for the duct burners. Therefore, the facility is required to meet the same emissions, performance testing, monitoring, reporting, and record keeping as those described in Subsection 3.3.1. FDEP periodically updates the NSPS that are adopted by reference. FDEP has authority for implementing NSPS requirements in Florida.

3.3.4 Florida Air Permitting Requirements

The FDEP regulations require any new source to obtain an air permit prior to construction. Minor modifications to major sources must comply with NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, and 62-210.300(1), F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.4 Source Applicability

3.4.1 Area Classification

The Project is located in Leon County, which has been designated by EPA and FDEP as an attainment area (includes unclassifiable) for all criteria pollutants. Leon County and surrounding counties are designated as PSD Class II areas for SO_2, PM_{10}, and NO_2. The site is located approximately 28 kilometers (km) from the PSD Class I area of the Bradwell Bay National Wilderness Area (NWA) and 38 km from the closest part of the PSD Class I area of the St. Marks NWA.

3.4.2 New Source Review

Pollutant Applicability

The existing Hopkins Generating Station is considered to be a major facility because the emissions of several regulated pollutants are estimated to exceed 100 TPY, and the emissions units are one of the 28 listed major source categories under the PSD rules.

The City of Tallahassee proposes to repower the existing 238-MW Unit No. 2 with the addition of one nominal 188-MW combined-cycle unit and the permanent shut down of the fossil fuel steam generator for Unit 2. The emissions of each unit have been previously described. A summary of the maximum potential annual emissions for the repowered Unit 2 with the emission reductions due to the shutdown of the existing Unit 2 boiler is presented in Table 3-3.

The PSD definition of a net emission increase consists of two additive components as follows:

- Any increase in actual emissions from a particular physical change or change in method of operation at a stationary source; and
- Any other increase and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

The first component narrowly includes only the emissions increases associated with a particular change at the source (the proposed CT emission). The second component more broadly includes all contemporaneous, source-wide (occurring anywhere at the entire source), creditable emission increases and decreases. For the Project, the shutdown of Unit No. 2 represents creditable emission decreases.

As shown in Table 3-3, potential annual emissions from the Hopkins Unit 2 Repowering Project, together with the emissions reductions due to the shutdown of the existing Unit 2 boiler, will not trigger PSD review for any regulated pollutant.

The maximum potential annual emissions were based the following operational scenarios at a turbine inlet temperature of 59 °F:

- CT operation when firing natural gas in combined cycle or simple cycle mode with exhaust gases routed through the HRSG and SCR system for 8,760 hours per year operation of the CT at full load for all pollutants except NO_x. For NO_x, the maximum annual emissions were based on the CT operation in simple cycle mode with exhaust gases routed through the emergency bypass stack for 8,760 hours per year operation of the CT at full load at full load. Only natural gas will be fired in this mode.
- Maximum duct firing with natural gas of 2,598,800 MMBtu/yr (HHV), which is equivalent to 3,650 hours/year operation at the maximum hourly duct firing rate.
- Maximum distillate oil-firing in the CT of 6,926,500 MMBtu/yr (HHV), which is equivalent to 3,500 hours of the CT at full load.

A summary of the maximum short-term emission proposed for the repowered unit is presented in Table 3-4..

Therefore, under PSD regulations, the Project is classified as a minor modification at a major source. As a result, the new source review requirements under the PSD regulations do not apply and the Project will not be required to undergo PSD review. Instead, the Project will be required to be reviewed under the general preconstruction review requirements in Rule 62-212.300, F.A.C., and subject to a final order issued pursuant to the PPSA.

Emission Standards

The applicable NSPS for the CTs is 40 CFR Part 60, Subpart GG, and the applicable NSPS for the duct burner is 40 CFR Part 60, Subpart Da. These NSPS are being replaced by Subpart KKKK.

For this Project, the NO_x emissions from the CT will be less than 0.2 lb/MW-hr for gas-firing and 0.42 lb/MW-hr for light oil firing for the combined cycle and simple cycle operations when the exhaust gases are routed to the HRSG and SCR system. For simple cycle operation when the exhaust gases are routed to the bypass stack, the NOx emissions from combustion turbine will be approximately 0.3 lb/MW-hr for gas-firing. For SO_2, the Project's emissions will be limited to a fuel sulfur content of 0.05 percent.

The NESHAPs Subpart YYYY may potentially apply to the Project. Information available from the EPA's emission database indicate that the Project will meet the proposed MACT of 91 ppbvd corrected to 15-percent O_2 for formaldehyde.

As previously discussed, the applicable federal NSPS for the duct burner are those promulgated by EPA on February 27, 2006, under 40 CFR Part 60, Subpart Da, which establish emission-limiting standards for PM, NO_x, and SO_2. EPA finalized new NSPS for these units that establish emission-limiting standards for PM, NO_x, and SO_2. However, HRSG and duct burners subject to the proposed NSPS, Subpart KKKK, such as the duct burner proposed for this Project would be exempt from the requirements of NSPS, Subpart Da. The emission limits proposed for the Project will be well less than the limits in Subpart Da.

Excess Emissions

The start-up and shutdown and fuel changes in combined cycle operation will require an excess emission allowance greater than 2 hours provided under the FDEP rules. During cold start-up, the operating load of the CTs is limited by the amount of steam that can be accepted by the steam turbine requiring low-load operation for longer than 2 hours and resulting in excess emissions during these periods. Major tuning sessions of the DLN combustors will also result in conditions where excess emissions may occur. An excess emission allowance is requested for this Project similar to the allowance authorized by the FDEP for the City's Purdom Repowering Project. The combined cycle unit associated with this facility has a similar steam turbine that receives steam during start-up. The proposed condition follows:

> Excess emissions resulting from startup, shutdown, malfunction, or fuel switching shall be permitted providing best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed the following in any 24-hour period: a total of six hours during any day including a cold startup; a total of four hours during any day that includes a hot startup; and a total of two hours during days not including a hot or cold startup. A cold startup is startup after the combined cycle unit has been down for more than 48 hours. A hot startup is startup after the combined cycle unit has been down for 48 hours or less.

In addition, excess emissions resulting from a major DLN/water injection tuning session without SCR operation shall be permitted provided the tuning session is performed in accordance with the manufacturer's specifications and in no case shall exceed 72 hours in any calendar year. A "major tuning session" would occur after a combustor change-out, a major repair to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be made by telephone, facsimile transmittal, or electronic mail.

3.4.3 Other Clean Air Act Requirements

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was delineated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (40 CFR Part 72), allowance system (Part 73), continuous emission monitoring (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

EPA's Acid Rain Program applies to all existing and new utility units except those serving a generator less than 25 MW, existing simple cycle CTs, and certain non-utility facilities; units that fall under the program are referred to as affected units. The EPA regulations are applicable to the Project for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the date on which the unit commences operation (e.g., first fire). (Rule 62-210.370). The City has submitted the Acid Rain Program application for this project.

The permit would require the units to hold SO_2 emission allowances. An allowance is a market-based financial instrument that is equivalent to 1 ton of SO_2 emissions. Allowances can be sold, purchased, or traded.

CEM for SO_2 and NO_x is required for gas-fired and oil-fired affected units. When an SO_2 CEM is selected to monitor SO_2 mass emissions, a flow monitor is also required. Alternately, SO_2 emissions may be determined using procedures established in Appendix D, 40 CFR Part 75 (flow-proportional oil sampling or manual daily oil sampling). CO_2 emissions must also be determined either through a CEM (e.g., as a diluent for NO_x monitoring) or calculation. Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75, Appendices A through I). The acid rain CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart GG. New units are required to meet the requirements by the later of January 1, 1995, or not later than 90 days after the unit commences commercial operation. The City will install a NOx CEMS and utilize the alternative procedures for SO_2 and CO_2 in accordance with the applicable Title IV appendixes.

TABLE 3-1

NATIONAL AND STATE AAQS, ALLOWABLE PSD INCREMENTS, AND SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	AAQS ($\mu g/m^3$)[a] Primary Standard	Secondary Standard	Florida	PSD Increments ($\mu g/m^3$)[a] Class I	Class II	PSD Class II Significant Impact Levels ($\mu g/m^3$)[b]
Particulate Matter[c] (PM_{10})	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150	150	150	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365	NA	260	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone[c]	1-Hour Maximum	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter (PM_{10}) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable, i.e., no standard exists.

[a] Short-term maximum concentrations are not to be exceeded more than once per year except for the PM_{10} and ozone AAQS. The 24-hour PM_{10} AAQS is attained when the expected number of days per year with a 24-hour concentration above 150 μ/m^3 is equal to or less than 1. For modeling purposes, compliance is based on the sixth highest 24-hour concentration over a 5-year period. For ozone, the daily maximum 1-hour concentration cannot be exceeded an average of more than one per year.

[b] Maximum concentrations are not to be exceeded.

[c] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 65 g/m^3 (3-year average of 98th percentile) and an annual standard of 15 g/m^3 (3-year average at community monitors).
The ozone standard was modified to be 0.08 ppm; achieved when 3-year average of 99th percentile is 0.08 ppm 157 μ/m^3 or less. FDEP has not yet adopted these standards.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50; 40 CFR 52.21.
Chapter 62-204, F.A.C.

TABLE 3-2
PSD SIGNIFICANT EMISSION RATES

Pollutant	Regulated Under	Significant Emission Rate (TPY)
Sulfur Dioxide	NAAQS, NSPS	40
Particulate Matter [PM(TSP)]	NSPS	25
Particulate Matter (PM_{10})	NAAQS	15
Nitrogen Dioxide	NAAQS, NSPS	40
Carbon Monoxide	NAAQS, NSPS	100
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40
Lead	NAAQS	0.6
Sulfuric Acid Mist	NSPS	7
Total Fluorides	NSPS	3
Total Reduced Sulfur	NSPS	10
Reduced Sulfur Compounds	NSPS	10
Hydrogen Sulfide	NSPS	10
Mercury	NESHAP	0.1

NAAQS = National Ambient Air Quality Standards.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.

Sources: 40 CFR 52.21; Rule 62-212.400.

TABLE 3-3
SUMMARY OF MAXIMUM POTENTIAL ANNUAL EMISSIONS FOR THE PROPOSED HOPKINS UNIT 2 REPOWERING PROJECT COMPARED TO THE PSD SIGNIFCANT EMISSION RATES

	Annual Emissions (TPY)								
	Maximum Potential Annual Emissions (TPY) for CT and DB Operating Scenarios [a]					Actual Emissions from Existing Unit 2 [b]	Emission Changes- Proposed Project with Existing Unit 2 Shutdown	PSD Significant Emission Rate (tons/year)	PSD Review Required?
Pollutant	A	B	C	D	E				
SO_2	43.4	50.5	211.7	211.7	43.4	1642.0	-1,430	40	No
PM	48.2	65.2	111.8	111.8	39.4	136.3	-25	25	No
PM_{10}	48.2	65.2	111.8	111.8	39.4	97.5	14	15	No
NO_x	142.0	164.9	243.7	265.7	255.6	843.3	-578	40	No
CO	171.1	264.6	340.1	340.1	171.1	241.1	99	100	No
VOC (as methane)	31.2	46.8	47.4	47.4	31.2	19.7	28	40	No
Sulfuric Acid Mist	4.3	5.8	39.7	39.7	4.3	73.0	-33	7	No
Lead	0.000	0.000	0.05	0.05	0.00	0.019	0	0.6	No
Mercury	0.0000	0.0000	0.00	0.00	0.00	0.0014	0	0.1	No

[a] Based on the following hours of operation for each operating scenario:

	A	B	C	D	E
Combined Cycle Operation					
CT, natural gas-firing	8,760	5,110	1,610	5,110	0
CT and duct burner, natural gas-firing	0	3,650	3,650	150	0
CT, fuel oil-firing	0	0	3,500	0	0
CT, fuel oil-firing; duct burner, natural gas-firing	0	0	0	3,500	0
CT, fuel oil-firing; duct burner, natural gas-firing					
Simple Cycle Operation	0	0	0	0	8,760

[b] Based on maximum annual average PM, PM10, CO, VOC, lead, and mercury emissions based on AOR data for the 24-month consecutive period from 2001 to 2005. For SO_2 and NO_x, based on the maximum annual average emissions from monthly CEM data from March 2001 to February 2006.

TABLE 3-4
SUMMARY OF MAXIMUM SHORT-TERM EMISSIONS
FOR THE PROPOSED HOPKINS UNIT 2 REPOWERING PROJECT

Pollutant		CT Natural Gas-Firing Emission Rate	CT Natural Gas-Firing Basis	CT Distillate Oil-Firing Emission Rate	CT Distillate Oil-Firing Basis
Combined Cycle Operation					
		No Duct Firing		*No Duct Firing*	
SO_2		9.9 lb/hr	2 gr S/100 scf	102.0 lb/hr	0.05% S
PM/PM_{10}	CT	9.0 lb/hr	filterable	37.6 lb/hr	filterable
PM/PM_{10}	CT/SCR	11.0 lb/hr	filterable	37.6 lb/hr	filterable
NO_x	CT/SCR	32.4 lb/hr	5 ppmvd@15%O2	77.5 lb/hr	10 ppmvd@15%O2
CO		39.1 lb/hr	9.9 ppmvd@15%O2	82.2 lb/hr	17.4 ppmvd@15%O2
VOC		7.1 lb/hr	3.16 ppmvd@15%O2	7.5 lb/hr	2.77 ppmvd@15%O2
		Duct Firing with Gas [a]		*Duct Firing with Gas* [a]	
SO_2		13.8 lb/hr	2 gr S/100 scf	105.9 lb/hr	2 gr S/100 scf (DB)
PM/PM_{10}	CT/SCR	20.3 lb/hr	filterable	47.0 lb/hr	filterable
NO_x	CT/SCR	45.0 lb/hr	5 ppmvd@15%O2	102.6 lb/hr	10 ppmvd@15%O2
CO		90.3 lb/hr	16.7 ppmvd@15%O2	133.4 lb/hr	21.2 ppmvd@15%O2
VOC		15.7 lb/hr	5.7 ppmvd@15%O2	16.0 lb/hr	5.2 ppmvd@15%O2
Simple Cycle Operation					
SO_2		9.9 lb/hr	2 gr S/100 scf	NA	
PM/PM_{10}		9.0 lb/hr	filterable	NA	
NO_x		58.4 lb/hr	9 ppmvd@15%O2	NA	
CO		39.1 lb/hr	9.9 ppmvd@15%O2	NA	
VOC		7.1 lb/hr	3.2 ppmvd@15%O2	NA	

Note: Based on 59 °F ambient inlet air temperature.
NA= not applicable

[a] Basis of duct burner emissions :

Pollutant	Natural Gas-Firing	Oil-Firing
PM_{10}	0.0120 lb/MMBtu	0.0150 lb/MMBtu
NO_x	0.10 lb/MMBtu	0.15 lb/MMBtu
CO	0.072 lb/MMBtu	0.10 lb/MMBtu
VOC	0.012 lb/MMBtu	0.012 lb/MMBtu

APPENDIX A

EXPECTED PERFORMANCE AND EMISSIONS INFORMATION FOR THE COMBUSTION TURBINE AND DUCT BURNER

TABLE A-SUM-1

SUMMARY OF MAXIMUM SHORT-TERM EMISSIONS FOR THE HOPKINS 2 REPOWERING PROJECT

	Maximum Hourly Emissions (lb/hr)[a, b]				
	Combined Cycle (CC)				Simple Cycle (SC)
CT Fuel:	NG	NG	FO	FO	NG
Load:	100%	100% w/DB on NG	100%	100% w/DB on NG	100%
Pollutant					
Combustion Turbine					
SO_2	9.90	13.8	102.0	105.9	9.90
PM	11.0	20.3	37.6	47.0	9.00
PM_{10}	11.0	20.3	37.6	47.0	9.00
NO_x	32.4	45.0	77.5	102.6	58.4
CO	39.1	90.3	82.2	133.4	39.1
VOC (as methane)	7.12	15.7	7.5	16.0	7.12
Sulfuric Acid Mist	0.99	1.77	20.4	21.2	0.99
Lead	0.00	0.00	0.028	0.028	0.00
Mercury	0.00	0.00	0.0024	0.0024	0.00
HAPs	0.78	1.09	2.45	2.45	0.78
Combustion Turbines: 2					
SO_2	19.8	27.6	204.0	211.9	19.8
PM	22.0	40.7	75.2	93.9	18.0
PM_{10}	22.0	40.7	75.2	93.9	18.0
NO_x	64.8	89.9	154.9	205.1	117
CO	78.1	181	164	266.9	78.1
VOC (as methane)	14.24	31.3	14.9	32.0	14.24
Sulfuric Acid Mist	1.98	3.55	40.80	42.4	1.98
Lead	0.00	0.00	0.055	0.055	0.00
Mercury	0.00	0.00	0.0047	0.0047	0.00
HAPs	1.56	2.17	4.91	4.9	1.56

[a] Based on 59 °F ambient inlet air temperature.
Source: GE, 2005 - CT Performance Data;
Golder, 2005

TABLE A-SUM-2
SUMMARY OF MAXIMUM ANNUAL EMISSIONS FOR THE HOPKINS 2 REPOWERING PROJECT

Operating Scenario	HP2 Repowering- Maximum Emissions (TPY) based on hours for					Actual [c] Emissions- 2-yr Average (TPY)	Net Emissions (Maximum Future Potential - Actual) based on hours for					PSD Significant Emission Rate (TPY)
	A	B	C	D	E		A	B	C	D	E	
CC/ CT-NG	8,760	5,110	1,610	5,110	0		8,760	5,110	1,610	5,110	0	
CC/ CT & DB- NG	0	3,650	3,650	150	0		0	3,650	3,650	150	0	
CC/ CT -FO	0	0	3,500	0	0		0	0	3,500	0	0	
	0	0	0	0	0		0	0	0	0	0	
CC/ CT -FO; DB -NG	0	0	0	3,500	0		0	0	0	3,500	0	
SC/ NG	0	0	0	0	8,760		0	0	0	0	8,760	
TOTAL	8,760	8,760	8,760	8,760	8,760		8,760	8,760	8,760	8,760	8,760	
Combustion Turbine												
SO_2	43.4	50.5	211.7	211.7	43.4	1,642.0	-1,599	-1,591	-1,430	-1,430	-1,599	40
PM	48.2	65.2	111.8	111.8	39.4	136.3	-88	-71	-25	-25	-97	25
PM_{10}	48.2	65.2	111.8	111.8	39.4	97.5	-49	-32	14	14	-58	15
NO_x	142.0	164.9	243.7	265.7	255.6	843.3	-701	-678	-600	-578	-588	40
CO	171.1	264.6	340.1	340.1	171.1	241.1	-70	23	99	99	-70	100
VOC (as methane)	31.2	46.8	47.4	47.4	31.2	19.7	11	27	28	28	11	40
Sulfuric Acid Mist	4.3	5.8	39.7	39.7	4.3	73.0	-68.7	-67.3	-33.3	-33.3	-68.7	7
Lead	0.00	0.00	0.05	0.05	0.00	0.02	-0.019	-0.019	0.030	0.030	-0.019	0.6
Mercury	0.000	0.000	0.004	0.004	0.000	0.0014	-0.001	-0.001	0.003	0.003	-0.001	0.1
HAPs	3.4	4.0	6.9	6.4	3.4							
Combustion Turbines: 2												
SO_2	87	101	423	423	87	1,642.0	-1,555	-1,541	-1,219	-1,219	-1,555	40
PM	96	130	223.6	224	79	136.3	-40	-6	87	87	-57	25
PM_{10}	96	130	223.6	224	79	97.5	-1	33	126	126	-19	15
NO_x	284	330	487	531	511	843.3	-559	-514	-356	-312	-332	40
CO	342	529	680	680	342	241.1	101	288	439	439	101	100
VOC (as methane)	62.4	93.5	94.7	94.7	62.4	19.7	43	74	75	75	43	40
Sulfuric Acid Mist	8.7	11.5	79.5	79.5	8.7	73.0	-64.4	-61.5	6.5	6.5	-64.4	7
Lead	0.000	0.000	0.097	0.097	0.000	0.02	-0.019	-0.019	0.08	0.08	-0.02	0.6
Mercury	0.000	0.000	0.008	0.008	0.000	0.0014	-0.001	-0.001	0.007	0.007	-0.001	0.1
HAPs	6.83	7.95	13.81	12.7	6.8							

[b] Basis of Emissions for Hopkins 2 Repowering:

	Natural gas		Fuel oil			
SO2	2 gr S/100 scf		0.050%	S		
PM	filterable			filterable		(includes ammonium sulfate from SCR for CC operation)
PM10	filterable			filterable		(includes ammonium sulfate from SCR for CC operation)
NOx	5 ppmvd	(5	10	ppmvd	(10	w/DB) CC operation (corrected to 15% oxygen)
NOx	9 ppmvd		NA			SC operation (corrected to 15% oxygen)
CO	12 ppmvd	(29	25	ppmvd	(50	w/DB)
VOC	3.5 ppmvw	(8.7	3.5	ppmvw	(7.9	w/DB) (assumes 50% UHC)

[c] Actual emissions based on CEMS for SO_2 and NO_x; AP-42 factors for other pollutants.
CEMS data used from March 2001 to February 2006. AOR data used 2001 to 2005.
Emission factors based on latest factors from AP-42 and used for all years (AOR emissions adjusted accordingly). PM/PM10 factors based on filterable PM.

TABLE A-1
DESIGN INFORMATION AND STACK PARAMETERS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, BASE LOAD, WITH NATURAL GAS DUCT FIRING

Parameter		CT Only Turbine Inlet Temperature				CT with Duct Burner (Natural Gas) Turbine Inlet Temperature		
		25 °F	59 °F	95 °F		25 °F w/DB	59 °F w/DB	95 °F w/DB
Combustion Turbine Performance								
Power output (MW)	p	187.8	174.40	160.3		187.8	174.4	160.3
Heat rate (Btu/kWh, LHV)	p	9,110	9,270	9,495		9,110	9,270	9,495
(Btu/kWh, HHV)		10,112	10,290	10,539		10,112	10,290	10,539
Heat Input (MMBtu/hr, LHV)	p	1,710.9	1,616.7	1,522		1,711	1,616.7	1,522
(MMBtu/hr, HHV)		1,899	1,795	1,689		1,899	1,795	1,689
Evaporative Cooler	p	Off	On	On		Off	On	On
Relative Humidity (%)	p	87	78	50		87	78	50
Natural gas								
Fuel heating value (Btu/lb, LHV)	p	20,714	20,714	20,714		20,714	20,714	20,714
(Btu/lb, HHV)		22,993	22,993	22,993		22,993	22,993	22,993
(HHV/LHV)		1.110	1.110	1.110		1.110	1.110	1.110
Duct Burner (DB)								
Heat input (MMBtu/hr, HHV)		0	0	0		765	712	663
(MMBtu/hr, LHV)		0	0	0		688.8	641.1	596.9
CT/DB Exhaust Flow								
Mass Flow (lb/hr)- with no margin		3,826,000	3,607,000	3,382,000	c	3,856,721.2	3,635,594	3,408,622
- provided	p	3,826,000	3,607,000	3,382,000				
Temperature (°F)	p	1,081	1,114	1,144		1,081	1,114	1,144
Moisture (% Vol.)	p	7.54	8.55	10.28	c	10.26	11.21	12.88
Oxygen (% Vol.)	p	12.77	12.57	12.22	c	9.76	9.61	9.30
Molecular Weight	c	28.49	28.38	28.19	c	28.31	28.20	28.02
	p	28.49	28.37	28.18				
Fuel Usage								
Natural Gas								
Fuel usage CT (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))								
Heat input (MMBtu/hr, LHV)		1,711	1,617	1,522		1,711	1,617	1,522
Heat content (Btu/lb, LHV)		20,714	20,714	20,714		20,714	20,714	20,714
Fuel usage (lb/hr)- calculated	c	82,596	78,049	73,477		82,596	78,049	73,477
		1,036						
Heat content (Btu/cf, LHV)- assumed		933	933	933		933	933	933
Fuel density (lb/ft^3)		0.0451	0.0451	0.0451		0.0451	0.0451	0.0451
Fuel usage (cf/hr)- calculated		1,832,961	1,732,040	1,630,584		1,832,961	1,732,040	1,630,584
Fuel Usage - Duct Burner Only								
Fuel usage (lb/hr)- calculated		0	0	0	c	33,253	30,950	28,816
Fuel usage (cf/hr)- calculated		0	0	0		737,941	686,838	639,485
Bypass Stack and Flow Conditions								
Stack Height (ft)		150	150	150		150	150	150
Diameter (ft)		18	18	18		18	18	18
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min								
Mass flow (lb/hr)		3,826,000	3,607,000	3,382,000		NA	NA	NA
Stack Temperature (°F)		1,081	1,114	1,144		NA	NA	NA
Molecular weight		28.49	28.38	28.19		NA	NA	NA
Volume flow (acfm)		2,517,808	2,433,691	2,341,021		NA	NA	NA
Diameter (ft)		18	18	18		NA	NA	NA
Velocity (ft/sec)- calculated		164.9	159.4	153.3		NA	NA	NA
HRSG Stack and Flow Conditions								
Stack Height (ft)		150	150	150		150	150	150
Diameter (ft)		18	18	18		18	18	18
Mass flow (lb/hr)		3,826,000	3,607,000	3,382,000		3,856,721	3,635,594	3,408,622
Stack Temperature (°F)		203.0	202.0	201.0		189.0	188.0	190
Molecular weight		28.49	28.38	28.19		28.31	28.20	28.02
Volume flow (acfm)		1,083,262	1,023,573	964,723		1,075,526	1,016,095	961,902
Diameter (ft)		18	18	18		18	18	18
Velocity (ft/sec)- calculated		70.9	67.0	63.2		70.4	66.5	63.0

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3.

Source: GE, 2006 - CT Performance Data; Golder, 2006 - DB Calculations.

TABLE A-2
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NOX COMBUSTOR, NATURAL GAS, BASE LOAD, WITH NATURAL GAS DUCT FIRING

Parameter	CT Only Turbine Inlet Temperature			CT with Duct Burner Turbine Inlet Temperature		
	25 °F	59 °F	95 °F	25 °F w/DB	59 °F w/DB	95 °F w/DB
Particulate from CT, DB, and SCR						
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only						
a. PM_{10} (front half) (lb/hr)						
CT- provided	9.0	9.0	9.0	9.0	9.0	9.0
DB (lb/hr) - calculated	0.0	0.0	0.0	9.2	8.5	8.0
Total CT/DB emission rate (lb/hr)	9.0	9.0	9.0	18.2	17.5	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})						
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3						
SO_2 emission rate (lb/hr)- calculated	10.5	9.9	9.3	14.7	13.8	13.0
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	2.12	2.00	1.88	2.97	2.79	2.62
CT emission rate (lb/hr) [a + b] assumes SCR	11.1	11.0	10.9	11.1	11.0	10.9
HRSG stack emission rate (lb/hr) [a + b]	11.1	11.0	10.9	21.1	20.3	19.6
(lb/mmBtu, HHV)	0.0059	0.0061	0.0064	0.0079	0.0081	0.0083
Sulfur Dioxide						
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100						
Fuel use (cf/hr)	1,832,961	1,732,040	1,630,584	2,570,901	2,418,878	2,270,068
Sulfur content (grains/ 100 cf)	2	2	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2	2	2
CT emission rate (lb/hr)	10.5	9.9	9.3	10.5	9.9	9.3
HRSG stack emission rate (lb/hr)	10.5	9.9	9.3	14.7	13.8	13.0
(lb/MW)	0.056	0.057	0.058			
Nitrogen Oxides						
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]						
CT/DB, ppmvd @15% O_2	9	9	9	14.5	14.4	14.4
Moisture (%)	7.54	8.55	10.28	10.26	11.21	12.88
Oxygen (%)	12.77	12.57	12.22	9.76	9.61	9.30
Turbine Flow (acfm)	2,517,808	2,433,691	2,341,021	2,553,753	2,468,107	2,373,678
Turbine Exhaust Temperature (°F)	1,081	1,114	1,144	1,081	1,114	1,144
CT emission rate (lb/hr)	61.8	58.4	55.0	61.8	58.4	55.0
(lb/MW)	0.3	0.3	0.3	NA	NA	NA
HRSG emission rate (lb/hr)	61.8	58.4	55.0	138.2	129.5	121.2
HRSG stack emission rate, ppmvd @ 15% O_2	5.0	5.0	5.0	5.0	5.0	5.0
HRSG Stack emission rate (lb/hr)	34.3	32.4	30.5	47.8	45.0	42.2
(lb/MW)	0.18	0.19	0.19			
Carbon Monoxide						
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppmvd	12	12	12	28.6	28.5	28.6
Basis, ppmvd @ 15% O2 - calculated	9.99	9.90	9.73	16.8	16.7	16.5
Moisture (%)	7.54	8.55	10.28	10.26	11.21	12.88
Oxygen (%)	12.77	12.57	12.22	9.76	9.61	9.30
Turbine Flow (acfm)	2,517,808	2,433,691	2,341,021	2,553,753	2,468,107	2,373,678
Turbine Exhaust Temperature (°F)	1,081	1,114	1,144	1,081	1,114	1,144
CT emission rate (lb/hr)	41.7	39.1	36.2	41.7	39.1	36.2
HRSG stack emission rate (lb/hr)	41.7	39.1	36.2	96.8	90.3	83.9

TABLE A-2
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NOX COMBUSTOR, NATURAL GAS, BASE LOAD, WITH NATURAL GAS DUCT FIRING

Parameter	CT Only Turbine Inlet Temperature			CT with Duct Burner Turbine Inlet Temperature		
	25 °F	59 °F	95 °F	25 °F w/DB	59 °F w/DB	95 °F w/DB
Volatile Organic Compounds						
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppmvw	3.50	3.50	3.50	8.6	8.7	8.8
Basis, ppmvd @ 15% O2 - calculated	3.15	3.16	3.16	5.67	5.71	5.80
Moisture (%)	7.54	8.55	10.28	10.26	11.21	12.88
Oxygen (%) wet	12.77	12.57	12.22	9.76	9.61	9.30
Oxygen (%) dry						
Turbine Flow (acfm)	2,517,808	2,433,691	2,341,021	2,553,753	2,468,107	2,373,678
Turbine Exhaust Temperature (°F)	1,081	1,114	1,144	1,081	1,114	1,144
CT emission rate (lb/hr)	7.52	7.12	6.72	7.52	7.12	6.72
HRSG stack Emission rate (lb/hr)	7.52	7.12	6.72	16.70	15.66	14.67
Sulfuric Acid Mist						
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100						
CT SO_2 emission rate (lb/hr) - provided	10.5	9.9	9.3	10.5	9.9	9.3
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	4	4	4
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20	20	20
CT emission rate (lb/hr)	1.05	0.99	0.93	1.05	0.99	0.93
HRSG stack Emission rate (lb/hr)	1.05	0.99	0.93	1.89	1.77	1.66
Lead						
Lead (lb/hr) = NA						
Emission Rate Basis	NA	NA	NA	NA	NA	NA
CT emission rate (lb/hr)	NA	NA	NA	NA	NA	NA
HRSG stack Emission rate (lb/hr)	NA	NA	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2006 - CT Performance Data; Golder, 2006 - DB Calculations.

TABLE A-3
DESIGN INFORMATION AND STACK PARAMETERS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, 75% LOAD

Parameter	Turbine Inlet Temperature		
	25 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	140.9	130.8	120.3
Heat rate (Btu/kWh, LHV)	9,840	10,080	10,410
(Btu/kWh, HHV)	10,923	11,189	11,555
Heat Input (MMBtu/hr, LHV)	1,387	1,319	1,252
(MMBtu/hr, HHV)	1,539	1,464	1,390
Relative Humidity (%)	87	78	50
Fuel heating value (Btu/lb, LHV)	20,714	20,714	20,714
(Btu/lb, HHV)	22,993	22,993	22,993
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with no margin	3,019,000	2,905,000	2,798,000
- provided	3,019,000	2,905,000	2,798,000
Temperature (°F)	1,136	1,161	1,186
Moisture (% Vol.)	7.66	8.45	9.74
Oxygen (% Vol.)	12.64	12.57	12.43
Molecular Weight	28.48	28.39	28.24
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,387	1,319	1,252
Heat content (Btu/lb, LHV)	20,714	20,714	20,714
Fuel usage (lb/hr)- calculated	66,935	63,653	60,457
Heat content (Btu/cf, LHV)- assumed	933	933	933
Fuel density (lb/ft^3)	0.0450	0.0450	0.0450
Fuel usage (cf/hr)- calculated	1,485,951	1,413,074	1,342,125
Bypass Stack and Flow Conditions			
Stack Height (ft)	150	150	150
Diameter (ft)	18	18	18
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	3,019,000	2,905,000	2,798,000
Stack Temperature (°F)	1,136	1,161	1,186
Molecular weight	28.48	28.39	28.24
Volume flow (acfm)	2,058,166	2,017,660	1,983,749
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	134.8	132.1	129.9
HRSG Stack and Flow Conditions			
Stack Height (ft)	150	150	150
Diameter (ft)	18	18	18
Mass flow (lb/hr)	3,019,000	2,905,000	2,798,000
Stack Temperature (°F)	187	188	190
Molecular weight	28.48	28.39	28.24
Volume flow (acfm)	834,099	806,317	783,135
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	54.6	52.8	51.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-4
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, 75% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half) (lb/hr)			
CT- provided	9.0	9.0	9.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	8.5	8.1	7.7
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	1.72	1.63	1.55
CT emission rate (lb/hr) [a]	9.0	9.0	9.0
HRSG stack emission rate (lb/hr) [a + b]	10.7	10.6	10.6
(lb/mmBtu, HHV)	0.0070	0.0073	0.0076
Sulfur Dioxide			
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100			
Fuel use (cf/hr)	1,485,951	1,413,074	1,342,125
Sulfur content (grains/ 100 cf)	2	2	2
lb SO_2 /lb S (64/32)	2	2	2
CT emission rate (lb/hr)	8.5	8.1	7.7
HRSG Stack emission rate (lb/hr)	8.5	8.1	7.7
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT / DB, ppmvd @15% O_2	9	9	9.0
Moisture (%)	7.66	8.45	9.74
Oxygen (%)	12.64	12.57	12.43
Turbine Flow (acfm)	2,058,166	2,017,660	1,983,749
Turbine Exhaust Temperature (°F)	1,136	1,161	1,186
CT Emission rate (lb/hr)	49.5	47.1	44.7
HRSG Stack emission rate, ppmvd @ 15% O_2	5	5	5.0
HRSG Stack emission rate (lb/hr)	27.5	26.2	24.9
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	12	12	12
Moisture (%)	7.66	8.45	9.74
Turbine Flow (acfm)	2,058,166	2,017,660	1,983,749
Turbine Exhaust Temperature (°F)	1,136	1,161	1,186
HRSG Exhaust Temperature (°F)	187	188	190
CT Emission rate (lb/hr)	32.9	31.5	30.0
HRSG Stack emission rate (lb/hr)	32.9	31.5	30.0

TABLE A-4
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, 75% LOAD

Parameter	Turbine Inlet Temperature		
	25 °F	59 °F	95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvw	3.50	3.5	3.50
Moisture (%)	7.66	8.45	9.74
Turbine Flow (acfm)	2,058,166	2,017,660	1,983,749
Turbine Exhaust Temperature (°F)	1,136	1,161	1,186
HRSG Exhaust Temperature (°F)	186.8	186.8	186.8
CT Emission rate (lb/hr)	5.94	5.73	5.55
HRSG Stack emission rate (lb/hr)	5.94	5.73	5.55
Sulfuric Acid Mist			
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100			
CT SO_2 emission rate (lb/hr) - provided	8.5	8.1	7.7
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20
CT Emission rate (lb/hr)	0.85	0.81	0.77
HRSG Stack emission rate (lb/hr)	0.85	0.81	0.77
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
CT Emission rate (lb/hr)	NA	NA	NA
HRSG Stack emission rate (lb/hr)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-5
DESIGN INFORMATION AND STACK PARAMETERS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, 60% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	112.7	104.6	96.2
Heat rate (Btu/kWh, LHV)	10,880	11,160	11,460
(Btu/kWh, HHV)	12,077	12,387	12,721
Heat Input (MMBtu/hr, LHV)	1,226	1,167	1,103
(MMBtu/hr, HHV)	1,361	1,296	1,224
Relative Humidity (%)	87	78	50
Fuel heating value (Btu/lb, LHV)	20,714	20,714	20,714
(Btu/lb, HHV)	22,993	22,993	22,993
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with no margin	2,707,000	2,608,000	2,523,000
- provided	2,707,000	2,608,000	2,523,000
Temperature (°F)	1,167	1,190	1,200
Moisture (% Vol.)	7.52	8.32	9.54
Oxygen (% Vol.)	12.80	12.73	12.66
Molecular Weight	28.49	28.40	28.25
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,226	1,167	1,103
Heat content (Btu/lb, LHV)	20,714	20,714	20,714
Fuel usage (lb/hr)- calculated	59,197	56,353	53,225
Heat content (Btu/cf, LHV)- assumed	933	933	933
Fuel density (lb/ft^3)	0.0450	0.0450	0.0450
Fuel usage (cf/hr)- calculated	1,314,153	1,251,028	1,181,580
Bypass Stack and Flow Conditions			
Stack Height (ft)	150	150	150
Diameter (ft)	18	18	18
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,707,000	2,608,000	2,523,000
Stack Temperature (°F)	1,167	1,190	1,200
Molecular weight	28.49	28.40	28.25
Volume flow (acfm)	1,880,545	1,843,332	1,803,432
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	123.2	120.7	118.1
HRSG Stack and Flow Conditions			
Stack Height (ft)	150	150	150
Diameter (ft)	18	18	18
Mass flow (lb/hr)	2,707,000	2,608,000	2,523,000
Stack Temperature (°F)	175	178	182
Molecular weight	28.49	28.40	28.25
Volume flow (acfm)	734,303	712,196	697,689
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	48.1	46.6	45.7

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-6
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, 60% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half) (lb/hr)			
CT- provided	9.0	9.0	9.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	7.5	7.1	6.8
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	1.52	1.44	1.36
CT emission rate (lb/hr) [a]	9.0	9.0	9.0
HRSG stack emission rate (lb/hr) [a + b]	10.5	10.4	10.4
(lb/mmBtu, HHV)	0.0077	0.0081	0.0085
Sulfur Dioxide			
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100			
Fuel use (cf/hr)	1,314,153	1,251,028	1,181,580
Sulfur content (grains/ 100 cf)	2	2	2
lb SO_2 /lb S (64/32)	2	2	2
CT emission rate (lb/hr)	7.5	7.1	6.8
HRSG Stack emission rate (lb/hr)	7.5	7.1	6.8
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT / DB, ppmvd @15% O_2	9	9	9
Moisture (%)	7.52	8.32	9.54
Oxygen (%)	12.80	12.73	12.66
Turbine Flow (acfm)	1,880,545	1,843,332	1,803,432
Turbine Exhaust Temperature (°F)	1,167	1,190	1,200
CT Emission rate (lb/hr)	43.5	41.4	39.1
HRSG Stack emission rate, ppmvd @ 15% O_2	5	5	5
HRSG Stack emission rate (lb/hr)	24.2	23.0	21.7

TABLE A-6
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, 60% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	12	12	12
Moisture (%)	7.52	8.32	9.54
Turbine Flow (acfm)	1,880,545	1,843,332	1,803,432
Turbine Exhaust Temperature (°F)	1,167	1,190	1,200
HRSG Exhaust Temperature (°F)	175	178	182
CT Emission rate (lb/hr)	29.5	28.3	27.1
HRSG Stack emission rate (lb/hr)	29.5	28.3	27.1
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvw	3.50	3.5	3.50
Moisture (%)	7.52	8.32	9.54
Turbine Flow (acfm)	1,880,545	1,843,332	1,803,432
Turbine Exhaust Temperature (°F)	1,167	1,190	1,200
HRSG Exhaust Temperature (°F)	175	175	175
CT Emission rate (lb/hr)	5.32	5.14	5.00
HRSG Stack emission rate (lb/hr)	5.32	5.14	5.00
Sulfuric Acid Mist			
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100			
CT SO_2 emission rate (lb/hr) - provided	7.5	7.1	6.8
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20
CT Emission rate (lb/hr)	0.75	0.71	0.68
HRSG Stack emission rate (lb/hr)	0.75	0.71	0.68
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
CT Emission rate (lb/hr)	NA	NA	NA
HRSG Stack emission rate (lb/hr)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-7
DESIGN INFORMATION AND STACK PARAMETERS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, BASE LOAD, WITH NATURAL GAS DUCT FIRING

Parameter		CT Only Turbine Inlet Temperature			CT with Duct Burner (Natural Gas) Turbine Inlet Temperature		
		25 °F	59 °F	95 °F	25 °F w/DB	59 °F w/DB	95 °F w/DB
Combustion Turbine Performance							
Power output (MW)	p	198.9	187.9	172.4	198.9	187.9	172.4
Heat rate (Btu/kWh, LHV)	p	9,860	9,935	10,090	9,860	9,935	10,090
(Btu/kWh, HHV)		10,452	10,531	10,695	10,452	10,531	10,695
Heat Input (MMBtu/hr, LHV)	p	1,961.2	1,866.8	1,739.5	1,961.2	1,866.8	1,739.5
(MMBtu/hr, HHV)		2,079	1,979	1,844	2,079	1,979	1,844
Evaporative Cooler		Off	On	On	Off	On	On
Relative Humidity (%)	p	87	78	50	87.0	78.0	50.0
Fuel oil							
Fuel heating value (Btu/lb, LHV)	p	18,300	18,300	18,300	18,300	18,300	18,300
(Btu/lb, HHV)		19,398	19,398	19,398	19,398	19,398	19,398
(HHV/LHV)		1.060	1.060	1.060	1.060	1.060	1.060
Fuel heating value (Btu/lb, LHV)		NA	NA	NA	18,300	18,300	18,300
(Btu/lb, HHV)		NA	NA	NA	19,398	19,398	19,398
(HHV/LHV)		NA	NA	NA	1.11	1.11	1.11
Duct Burner (DB)							
Heat input (MMBtu/hr, HHV)		0	0	0	764.6	711.6	662.6
(MMBtu/hr, LHV)		0	0	0	688.8	641.1	596.9
CT Exhaust Flow							
Mass Flow (lb/hr)- with no margin		3,995,000	3,764,000	3,512,000	4,025,724	3,792,596	3,538,625
- provided	p	3,995,000	3,764,000	3,512,000			
Temperature (°F)	p	1,059	1,096	1,130	1,059	1,096	1,130
Moisture (% Vol.)	p	10.95	11.82	12.96	13.50	14.32	15.43
Oxygen (% Vol.)	p	11.20	10.97	10.77	8.35	8.16	7.98
Molecular Weight	c	28.36	28.26	28.13	28.19	28.10	27.97
	p	28.35	28.26	28.13			
Fuel Usage							
Fuel oil							
Fuel usage CT (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))							
Heat input (MMBtu/hr, LHV)		1,961	1,867	1,740	NA	NA	NA
Heat content (Btu/lb, LHV)		18,300	18,300	18,300	NA	NA	NA
Fuel usage (lb/hr)- calculated	c	107,169	102,011	95,055	NA	NA	NA
Natural gas							
Fuel usage DB (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))							
Heat input (MMBtu/hr, LHV)		NA	NA	NA	688.8	641.1	596.9
Heat content (Btu/lb, LHV)		NA	NA	NA	20,714	20,714	20,714
Fuel usage (lb/hr)- calculated		NA	NA	NA	33,253	30,950	28,816
Heat content (Btu/cf, LHV)- assumed		NA	NA	NA	933	933	933
Fuel density (lb/ft^3)		NA	NA	NA	0.0451	0.0451	0.0451
Fuel usage (cf/hr)- calculated		NA	NA	NA	737,941	686,838	639,485
Bypass Stack and Flow Conditions							
Stack Height (ft)		150	150	150	150	150	150
Diameter (ft)		18	18	18	18	18	18
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min							
Mass flow (lb/hr)		3,995,000	3,764,000	3,512,000	NA	NA	NA
Stack Temperature (°F)		1,059	1,096	1,130	NA	NA	NA
Molecular weight		28.36	28.26	28.13	NA	NA	NA
Volume flow (acfm)		2,603,400	2,520,733	2,414,634	NA	NA	NA
Diameter (ft)		18	18	18	NA	NA	NA
Velocity (ft/sec)- calculated		170.5	165.1	158.1	NA	NA	NA
HRSG Stack and Flow Conditions							
Stack Height (ft)		150	150	150	150	150	150
Diameter (ft)		18	18	18	18	18	18
Mass flow (lb/hr)		3,995,000	3,764,000	3,512,000	4,025,724	3,792,596	3,538,625
Stack Temperature (°F)		248.0	248.0	247.0	206	204	201
Molecular weight		28.36	28.26	28.13	28.19	28.10	27.97
Volume flow (acfm)		1,213,435	1,146,966	1,073,677	1,157,102	1,090,210	1,017,182
Diameter (ft)		18	18	18	18	18	18
Velocity (ft/sec)- calculated		79.5	75.1	70.3	75.8	71.4	66.6

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-8
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, BASE LOAD, WITH NATURAL GAS DUCT FIRING

Parameter	CT Only Turbine Inlet Temperature			CT with Duct Burner (Natural Gas) Turbine Inlet Temperature		
	25 °F	59 °F	95 °F	25 °F w/DB	59 °F w/DB	95 °F w/DB
Particulate from CTand SCR						
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only						
a. PM_{10} (front half) (lb/hr)						
CT- provided	17.0	17.0	17.0	17.0	17.0	17.0
DB (lb/hr) - calculated	0.0	0.0	0.0	9.2	8.5	8.0
Total CT/DB emission rate (lb/hr)	17.0	17.0	17.0	26.2	25.5	25.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})						
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3						
SO_2 emission rate (lb/hr)- calculated	107.2	102.0	95.1	111.4	105.9	98.7
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	21.66	20.62	19.21	22.51	21.41	19.95
CT emission rate (lb/hr) [a + b] assumes SCR	38.7	37.6	36.2	38.7	37.6	36.2
HRSG stack emission rate (lb/hr) [a + b]	38.7	37.6	36.2	48.7	47.0	44.9
(lb/mmBtu, HHV)	0.0186	0.0190	0.0196	0.0171	0.0175	0.0179
Sulfur Dioxide						
CT/SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100						
Fuel oil Sulfur Content	0.0500%	0.0500%	0.0500%	0.0500%	0.0500%	0.0500%
Fuel oil use (lb/hr)	107,169	102,011	95,055	NA	102,011	95,055
lb SO2 / lb S (64/32)	2	2	2	2	2	2
DB/SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100						
Fuel use (cf/hr)	NA	NA	NA	737,941	686,838	639,485
Sulfur content (grains/ 100 cf)	NA	NA	NA	2	2	2
CT emission rate (lb/hr)	107.2	102.0	95.1	107.2	102.0	95.1
HRSG stack emission rate (lb/hr)	107.2	102.0	95.1	111.4	105.9	98.7
(lb/MW)	0.54	0.54	0.55			
Nitrogen Oxides						
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]						
CT/DB, ppmvd @15% O_2	42	42	42	38.6	38.7	38.7
Moisture (%)	10.95	11.82	12.96	13.50	14.32	15.43
Oxygen (%)	11.20	10.97	10.77	8.35	8.16	7.98
Turbine Flow (acfm)	2,603,400	2,520,733	2,414,634	2,639,095	2,554,769	2,446,776
Turbine Exhaust Temperature (°F)	1,059	1,096	1,130	1,059	1,096	1,130
CT emission rate (lb/hr)	341.9	325.3	303.4	418.4	396.5	369.6
(lb/MW)	1.7	1.7	1.8	NA	NA	NA
HRSG stack emission rate, ppmvd @ 15% O_2	10	10	10	10	10	10
HRSG stack emission rate (lb/hr)	81.4	77.5	72.2	108.4	102.6	95.6
(lb/MW)	0.41	0.41	0.42			
Carbon Monoxide						
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppmvd	25	25	25	41.9	41.8	41.9
Basis, ppmvd @ 15% O_2	17.72	17.44	17.30	21.44	21.18	21.14
Moisture (%)	10.95	11.82	12.96	13.74	14.55	15.62
Oxygen (%)	11.20	10.97	10.77	8.07	7.90	7.76
Turbine Flow (acfm)	2,603,400	2,520,733	2,414,634	2,639,095	2,554,769	2,446,776
Turbine Exhaust Temperature (°F)	1,059	1,096	1,130	1,059	1,096	1,130
CT emission rate (lb/hr)	87.8	82.2	76.1	87.8	82.2	76.1
HRSG Stack emission rate (lb/hr)	87.8	82.2	76.1	142.9	133.4	123.8

TABLE A-8
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, BASE LOAD, WITH NATURAL GAS DUCT FIRING

Parameter	CT Only Turbine Inlet Temperature			CT with Duct Burner (Natural Gas) Turbine Inlet Temperature		
	25 °F	59 °F	95 °F	25 °F w/DB	59 °F w/DB	95 °F w/DB
Volatile Organic Compounds						
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppmvw	3.50	3.50	3.50	7.6	7.5	7.5
Basis, ppmvd	3.93	3.97	4.02	8.8	8.8	8.9
Basis, ppmvd @ 15% O_2	2.79	2.77	2.78	5.2	5.2	5.3
Moisture (%)	10.95	11.82	12.96	13.74	14.55	15.62
Oxygen (%)	11.20	10.97	10.77	8.07	7.90	7.76
Oxygen (%-dry)	12.58	12.44	12.37	9.36	9.25	9.20
Turbine Flow (acfm)	2,603,400	2,520,733	2,414,634	2,639,095	2,554,769	2,446,776
Turbine Exhaust Temperature (°F)	1,059	1,096	1,130	1,059	1,096	1,130
CT emission rate (lb/hr)	7.89	7.46	6.99	7.89	7.46	6.99
HRSG Stack emission rate (lb/hr)	7.89	7.46	6.99	17.1	16.0	14.9
Sulfuric Acid Mist						
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100						
CT SO_2 emission rate (lb/hr) - provided	107.2	102.0	95.1	111.4	105.9	98.7
CT Conversion to H_2SO_4 (% by weight)	20	20	20	20	20	20
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0.0	0.0	0.0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20	20	20
CT emission rate (lb/hr)	21.4	20.4	19.0	21.4	20.4	19.0
HRSG Stack emission rate (lb/hr)	21.4	20.4	19.0	22.3	21.2	19.7
Lead						
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu						
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14	14	14
CT emission rate (lb/hr)	0.0291	0.0277	0.0258	0.0291	0.0277	0.0258
HRSG stack Emission rate (lb/hr)	0.0291	0.0277	0.0258	0.0291	0.0277	0.0258

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-9
DESIGN INFORMATION AND STACK PARAMETERS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, 75% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	149.2	140.9	129.3
Heat rate (Btu/kWh, LHV)	10,580	10,740	10,940
(Btu/kWh, HHV)	11,215	11,385	11,596
Heat Input (MMBtu/hr, LHV)	1,579	1,513	1,415
(MMBtu/hr, HHV)	1,673	1,604	1,499
Relative Humidity (%)	87	78	50
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
CT Exhaust Flow			
Mass Flow (lb/hr)- with no margin	3,085,000	2,993,000	2,848,000
- provided	3,085,000	2,993,000	2,848,000
Temperature (°F)	1,136	1,159	1,184
Moisture (% Vol.)	10.91	11.46	12.22
Oxygen (% Vol.)	10.96	10.96	10.96
Molecular Weight	28.38	28.31	28.21
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,579	1,513	1,415
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	86,257	82,694	77,295
HRSG Stack and Flow Conditions			
Stack Height (ft)	150	150	150
Diameter (ft)	18	18	18
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	3,085,000	2,993,000	2,848,000
Stack Temperature (oF)	233	233	232
Molecular weight	28.38	28.31	28.21
Volume flow (acfm)	916,430	891,229	849,841
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	60.0	58.4	55.7

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-10
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, 75% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half) (lb/hr)			
CT- provided	17.0	17.0	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	86.3	82.7	77.3
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	17.43	16.71	15.62
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
HRSG stack emission rate (lb/hr) [a + b]	34.4	33.7	32.6
(lb/mmBtu, HHV)	0.0206	0.0210	0.0218
Sulfur Dioxide			
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100			
Fuel oil Sulfur Content	0.050%	0.050%	0.050%
Fuel oil use (lb/hr)	86,257	82,694	77,295
lb SO2 / lb S (64/32)	2	2	2
CT emission rate (lb/hr)	86.3	82.7	77.3
HRSG Stack emission rate (lb/hr)	86.3	82.7	77.3
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT/DB, ppmvd @15% O_2	42	42	42
Moisture (%)	10.91	11.46	12.22
Oxygen (%)	10.96	10.96	10.96
Turbine Flow (acfm)	2,110,565	2,082,106	2,018,987
Turbine Exhaust Temperature (°F)	1,136	1,159	1,184
CT Emission rate (lb/hr)	272.7	261.2	244.2
HRSG Stack emission rate, ppmvd @ 15% O_2	10	10	10.0
HRSG Stack emission rate (lb/hr)	64.9	62.2	58.1
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	25	25	25
Moisture (%)	10.91	11.46	12.22
Turbine Flow (acfm)	2,110,565	2,082,106	2,018,987
Turbine Exhaust Temperature (°F)	1,136	1,159	1,184
HRSG Exhaust Temperature (°F)	233	233	232
CT Emission rate (lb/hr)	67.8	65.5	62.0
HRSG Stack emission rate (lb/hr)	67.8	65.5	62.0

TABLE A-10
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, 75% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvw	3.5	3.5	3.5
Moisture (%)	10.91	11.46	12.22
Turbine Flow (acfm)	10.96	10.96	10.96
Turbine Exhaust Temperature (°F)	2,110,565	2,082,106	2,018,987
HRSG Exhaust Temperature (°F)	1,136	1,159	1,184
CT Emission rate (lb/hr)	6.09	5.92	5.65
HRSG Stack emission rate (lb/hr)	6.09	5.92	5.65
Sulfuric Acid Mist			
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100			
CT SO_2 emission rate (lb/hr) - provided	86.3	82.7	77.3
CT Conversion to H_2SO_4 (% by weight) - provided	20	20	20
DB SO_2 emission rate (lb/hr) - provided	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20
CT Emission rate (lb/hr)	17.25	16.54	15.46
HRSG Stack emission rate (lb/hr)	17.25	16.54	15.46
Lead			
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Emission Rate Basis (lb/10^{12} Btu)	14	14	14
CT Emission rate (lb/hr)	0.0221	0.0212	0.0198
HRSG Stack emission rate (lb/hr)	0.0221	0.0212	0.0198

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-11
DESIGN INFORMATION AND STACK PARAMETERS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, 60% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	119.4	112.7	103.5
Heat rate (Btu/kWh, LHV)	11,570	11,750	12,010
(Btu/kWh, HHV)	12,265	12,455	12,730
Heat Input (MMBtu/hr, LHV)	1,382	1,324	1,243
(MMBtu/hr, HHV)	1,464	1,404	1,318
Relative Humidity (%)	87	78	50
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
CT Exhaust Flow			
Mass Flow (lb/hr)- with no margin	2,743,000	2,667,000	2,579,000
- provided	2,743,000	2,667,000	2,579,000
Temperature (°F)	1,167	1,188	1,200
Moisture (% Vol.)	10.42	10.96	11.63
Oxygen (% Vol.)	11.23	11.23	11.33
Molecular Weight	28.42	28.35	28.25
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,382	1,324	1,243
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	75,492	72,361	67,923
HRSG Stack and Flow Conditions			
Stack Height (ft)	150	150	150
Diameter (ft)	18	18	18
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,743,000	2,667,000	2,579,000
Stack Temperature (oF)	223	223	222
Molecular weight	28.42	28.35	28.25
Volume flow (acfm)	802,010	781,670	757,255
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	52.5	51.2	49.6

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-12
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, 60% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half) (lb/hr)			
CT- provided	17.0	17.0	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	75.5	72.4	67.9
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	15.26	14.63	13.73
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
HRSG stack emission rate (lb/hr) [a + b]	32.3	31.6	30.7
(lb/mmBtu, HHV)	0.0220	0.0225	0.0233
Sulfur Dioxide			
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100			
Fuel oil Sulfur Content	0.050%	0.050%	0.050%
Fuel oil use (lb/hr)	75,492	72,361	67,923
lb SO2 / lb S (64/32)	2	2	2
CT emission rate (lb/hr)	75.5	72.4	67.9
HRSG Stack emission rate (lb/hr)	75.5	72.4	67.9
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT/DB, ppmvd @15% O_2	42	42	42
Moisture (%)	10.42	10.96	11.63
Oxygen (%)	11.23	11.23	11.33
Turbine Flow (acfm)	1,910,499	1,886,080	1,843,173
Turbine Exhaust Temperature (°F)	1,167	1,188	1,200
CT Emission rate (lb/hr)	236.8	227.3	213.4
HRSG Stack emission rate, ppmvd @ 15% O_2	10	10	10.0
HRSG Stack emission rate (lb/hr)	56.4	54.1	50.8
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	25	25	25
Moisture (%)	10.42	10.96	11.63
Turbine Flow (acfm)	1,910,499	1,886,080	1,843,173
Turbine Exhaust Temperature (°F)	1,167	1,188	1,200
HRSG Exhaust Temperature (°F)	28	28	28
CT Emission rate (lb/hr)	60.5	58.6	56.5
HRSG Stack emission rate (lb/hr)	60.5	58.6	56.5

TABLE A-12
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, 60% LOAD

Parameter	Turbine Inlet Temperature 25 °F	59 °F	95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 x Volume flow (acfm) x			
16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvw	3.5	3.5	3.5
Moisture (%)	10.42	10.96	11.63
Turbine Flow (acfm)	11.23	11.23	11.33
Turbine Exhaust Temperature (°F)	1,910,499	1,886,080	1,843,173
HRSG Exhaust Temperature (°F)	1,167	1,188	1,200
CT Emission rate (lb/hr)	5.41	5.27	5.11
HRSG Stack emission rate (lb/hr)	5.41	5.27	5.11
Sulfuric Acid Mist			
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100			
CT SO_2 emission rate (lb/hr) - provided	75.5	72.4	67.9
CT Conversion to H_2SO_4 (% by weight) - provided	20	20	20
DB SO_2 emission rate (lb/hr) - provided	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20
CT Emission rate (lb/hr)	15.10	14.47	13.58
HRSG Stack emission rate (lb/hr)	15.10	14.47	13.58
Lead			
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Emission Rate Basis (lb/10^{12} Btu)	14	14	14
CT Emission rate (lb/hr)	0.0193	0.0185	0.0174
HRSG Stack emission rate (lb/hr)	0.0193	0.0185	0.0174

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-13
DUCT BURNER EMISSIONS: FULL DUCT FIRING

Pollutant	Emission Rate (lb/MMBtu)	AP-42	Heat Input (MMBtu/hr) (HHV) 25 °F	59 °F	95 °F	Emission Rate (lb/hr) 25 °F	59 °F	95 °F
Natural Gas-Firing								
PM-10	0.012		765	712	663	9.2	8.5	8.0
NO_x	0.10		765	712	663	76.5	71.2	66.3
CO	0.072		765	712	663	55.0	51.2	47.7
VOC	0.012		765	712	663	9.2	8.5	8.0

Natural gas-firing	AP-42 (1998)		
PM-10	1.9 lb/10^6 scf	a	0.0018 lb/MMBtu
NOx	190 lb/10^6 scf	b	0.183 lb/MMBtu
CO	84 lb/10^6 scf	b	0.081 lb/MMBtu
VOC	5.5 lb/10^6 scf	a	0.0053 lb/MMBtu

Heat content 1036 Btu/scf

[a] Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion, Uncontrolled Post-NSPS

[b] Table 1.4-1. Emission Factors for Nitrogen Oxides (NOx) and Carbon Monoxide (CO) from Natural Gas Combustion

TABLE A-14
REGULATED AND HAZARDOUS AIR POLLUTANT EMISSION FACTORS AND EMISSIONS
FOR HOPKINS UNIT 2 REPOWERING PROJECT, NATURAL GAS-FIRING ONLY

Parameter	Emission Rate (lb/hr) firing Natural Gas for Operating Conditions of Base Load [a]		Natural Gas Maximum Annual Emissions (TPY) [b]
Ambient Temperature (°F):	59 °F	59 °F w/DB	59 °F
HIR (MMBtu/hr):	1,795	2,506	1 CT/HRSG
HAPs (Section 112(b) of Clean Air Act)			
1,3-Butadiene	7.72E-04	1.08E-03	4.18E-03
Acetaldehyde	7.18E-02	1.00E-01	3.89E-01
Acrolein	1.15E-02	1.60E-02	6.23E-02
Benzene	2.15E-02	3.01E-02	1.17E-01
Ethylbenzene	5.74E-02	8.02E-02	3.11E-01
Formadehyde	3.85E-01	5.34E-01	2.08E+00
Naphthalene	2.33E-03	3.26E-03	1.27E-02
Polycyclic Aromatic Hydrocarbons (PAH) [c]	3.95E-03	5.51E-03	2.14E-02
Propylene Oxide	5.20E-02	7.27E-02	2.82E-01
Toluene	5.92E-02	8.27E-02	3.21E-01
Xylene	1.15E-01	1.60E-01	6.23E-01
Antimony	0.00E+00	0.00E+00	0.00E+00
Arsenic	0.00E+00	0.00E+00	0.00E+00
Beryllium	0.00E+00	0.00E+00	0.00E+00
Cadmium	0.00E+00	0.00E+00	0.00E+00
Chromium	0.00E+00	0.00E+00	0.00E+00
Lead	0.00E+00	0.00E+00	0.00E+00
Manganese	0.00E+00	0.00E+00	0.00E+00
Mercury	0.00E+00	0.00E+00	0.00E+00
Nickel	0.00E+00	0.00E+00	0.00E+00
Selenium	0.00E+00	0.00E+00	0.00E+00
HAPs (Total)	0.780	1.086	4.22

[a] Emissions based on the following emission factors and conversion factors for firing natural gas:

Emission Factors		Value	Reference
1,3-Butadiene	(a)	0.43	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Acetaldehyde		40	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Acrolein		6.4	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Benzene		12	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Ethylbenzene		32	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Formadehyde		0.091	ppmvd @15% O_2 (see Table 15a)
Naphthalene		1.3	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)		2.2	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Propylene Oxide	(a)	29	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Toluene		33	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000. Database
Xylene		64	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Antimony		0.00E+00	
Arsenic		0.00E+00	
Beryllium		0.00E+00	
Cadmium		0.00E+00	
Chromium		0.00E+00	
Lead		0.00E+00	
Manganese		0.00E+00	
Mercury		0.00E+00	
Nickel		0.00E+00	
Selenium		0.00E+00	

(a) Based on 1/2 the detection limit; expected emissions are lower.

[b] Annual emissions based on ambient temperature of 59 °F firing natural gas for following hours:
3,500 hours, NG w/o duct firing
5,260 hours, NG w/ duct firing

[c] Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

TABLE A-15
MAXIMUM FORMALDEHYDE EMISSIONS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, NATURAL GAS, BASE LOAD

Parameter	CT Only Turbine Inlet Temperature 25 °F	59 °F	25 °F w/DB	59 °F w/DB
Formaldehyde (CH_2O) MW =	30			
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT, ppmvd @15% O_2	0.091	0.091	0.091	0.091
Moisture (%)	7.54	8.55	10.26	11.21
Oxygen (%)	12.77	12.57	9.76	9.61
Turbine Flow (acfm)	1,083,262	1,023,573	1,075,526	1,016,095
Turbine Exhaust Temperature (°F)	203	202	189	188
CT Emission rate (lb/hr)	0.407	0.385	0.567	0.534
CT Emission rate (lb/10^{12} Btu) (HHV)	214.5	214.4	213.0	200.4

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

TABLE A-16
REGULATED AND HAZARDOUS AIR POLLUTANT EMISSION FACTORS AND EMISSIONS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
NATURAL GAS-FIRING AND DISTILLATE OIL-FIRING

Parameter	Emission Rate (lb/hr) Firing Distillate Fuel Oil [a] Base Load	Maximum Annual Emissions (TPY)		
Ambient Temperature (°F):	59 °F	Distillate Fuel Oil [b]	Natural Gas [d]	Natural Gas and Fuel Oil [e]
		1	1	
HIR (MMBtu/hr):	1,979	CT/HRSG	CT/HRSG	
HAPs (Section 112(b) of Clean Air Act)				
1,3-Butadiene	3.17E-02	3.17E-02	4.18E-03	3.45E-02
Acetaldehyde	0.00E+00	0.00E+00	3.89E-01	2.64E-01
Acrolein	0.00E+00	0.00E+00	6.23E-02	4.22E-02
Benzene	1.09E-01	1.09E-01	1.17E-01	1.88E-01
Ethylbenzene	0.00E+00	0.00E+00	3.11E-01	2.11E-01
Formadehyde	4.60E-01	4.60E-01	2.08E+00	1.86E+00
Naphthalene	6.93E-02	6.93E-02	1.27E-02	7.78E-02
Polycyclic Aromatic Hydrocarbons (PAH) [c]	7.92E-02	7.92E-02	2.14E-02	9.37E-02
Propylene Oxide	0.00E+00	0.00E+00	2.82E-01	1.91E-01
Toluene	0.00E+00	0.00E+00	3.21E-01	2.18E-01
Xylene	0.00E+00	0.00E+00	6.23E-01	4.22E-01
Antimony	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Arsenic	2.18E-02	2.18E-02	0.00E+00	2.18E-02
Beryllium	6.13E-04	6.13E-04	0.00E+00	6.13E-04
Cadmium	9.50E-03	9.50E-03	0.00E+00	9.50E-03
Chromium	2.18E-02	2.18E-02	0.00E+00	2.18E-02
Lead	2.77E-02	2.77E-02	0.00E+00	2.77E-02
Manganese	1.56E+00	1.56E+00	0.00E+00	1.56E+00
Mercury	2.37E-03	2.37E-03	0.00E+00	2.37E-03
Nickel	9.10E-03	9.10E-03	0.00E+00	9.10E-03
Selenium	4.95E-02	4.95E-02	0.00E+00	4.95E-02
HAPs (Total)	2.45	1.64	4.2	5.3

[a] Emissions based on the following emission factors and conversion factors for firing distillate fuel oil:

Emission Factors		Valu	Reference
Sulfuric acid mist		5	%; Conversion of SO_2 to SO_3 in gas turbine
1,3-Butadiene	(a)	16	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Acetaldehyde		0.0	
Acrolein		0.0	
Benzene		55	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Ethylbenzene		0.0	
Formadehyde		###	ppmvd @15% O_2 (see Table 16a)
Naphthalene		35	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)		40	lb/10^{12} Btu; AP-42,Table 3.1-4. EPA 2000
Propylene Oxide		0.0	
Toluene		0.0	
Xylene		0.0	
Antimony		0.0	
Arsenic	(a)	11	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Beryllium	(a)	0.3	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Cadmium		4.8	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Chromium		11	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Lead		14	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Manganese		790	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Mercury		1.2	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Nickel	(a)	4.6	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Selenium	(a)	25	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000

(a) Based on 1/2 the detection limit; expected emissions are lower.

[b] Annual emissions based on ambient temperature of 59 °F and firing fuel oil at base load for : 3,500 hours, FO w/o duct firing

[c] Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

[d] Annual emissions based on maximum emissions presented for natural gas-firing
3,500 hours, NG w/o duct firing
5,260 hours, NG w/ duct firing

[e] Maximum total annual emissions based on maximum oil-firing and natural gas firing:
0 hours, NG w/o duct firing
5,260 hours, NG w/ duct firing

TABLE A-17
MAXIMUM FORMALDEHYDE EMISSIONS FOR THE HOPKINS UNIT 2 REPOWERING PROJECT
GE FRAME 7FA, DRY LOW NO_X COMBUSTOR, DISTILLATE OIL, BASE LOAD

Parameter		CT Only Turbine Inlet Temperature 25 °F	CT Only Turbine Inlet Temperature 59 °F
Formaldehyde (CH_2O) MW =	30		
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2		0.091	0.091
Moisture (%)		10.95	11.82
Oxygen (%)		11.20	10.97
Exhaust Flow (acfm)		1,213,435	1,146,966
Exhaust Temperature (°F)		248	248
CT Emission rate (lb/hr)		0.483	0.460
CT Emission rate (lb/10^{12} Btu) (HHV)		232.4	232.3

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Source: GE, 2006 - CT Performance Data; Golder, 2006.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

January 19, 2006

CERTIFIED MAIL - RETURN RECEIPT REQUESTED
Ms. Jennette Curtis
Environmental Services Administrator
City of Tallahassee
300 South Adams Street
Tallahassee, FL 32301

Re: Submittal of Application for Title V Revision for Permit No. 0730003-005-AC
Arvah B. Hopkins Generating Station
Combustion Turbine Nos. HC3 and HC4

Dear Ms. Curtis,

On January 11, 2006, the City of Tallahassee requested the Department confirm the date for submittal of the Title V revision application for air construction permit 0730003-005-AC. The project was for the construction of two combustion turbines (CT) at the Arvah B. Hopkins Generating Station. CT unit no. HC3 (EU 031) had an initial startup of July 31, 2005 and CT unit no. HC4 (EU032) had an initial startup of September 27, 2005. City of Tallahassee is requesting the Department confirm the Title V revision submittal date be based upon the September 27, 2005 initial startup date of HC4. The Department agrees and a Title V application pursuant to air construction permit 0730003-005-AC and Rule 62-213.240, F.A.C. must be submitted 180 days from September 27, 2005.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permitting decision is issued pursuant to Chapter 403, Florida Statutes.

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

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

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

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

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this order will not be effective until further order of the Department.

Any party to this permitting decision (order) has the right to seek judicial review of it under section 120.68 of the Florida Statutes, 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 thirty days after this order is filed with the clerk of the Department. Executed in Tallahassee, Florida.

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this order was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 1/19/06 to the person(s) listed:

Sandra Veazey, FDEP, NED
John Powell, City of Tallahassee
Cynthia Barber, City of Tallahassee
Phil Bucci, City of Tallahassee
Kevin Wailes, City of Tallahassee
Rob McGarrah, City of Tallahassee
Triveni Singh, City of Tallahassee

Clerk Stamp

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

(Clerk) 1/19/06
(Date)

City of Tallahassee
Your Own Utilities℠

300 South Adams Street, Tallahassee, Florida 32301, (850) 891-4YOU (4968), talgov.com

January 9, 2006

Certified Mail No. 70041160000059423495

RECEIVED
JAN 11 2006
BUREAU OF AIR REGULATION

Jeff Koerner
Professional Engineer Administrator
Florida Department of Environmental Protection
2600 Blair Stone Road, M.S. 5500
Tallahassee, Florida 32399-2400

Re: Application for Title V Air Operation Permit
Combustion Turbine Nos. HC3 and HC4
Arvah B. Hopkins Generating Station
Title V Air Construction Permit No. 0730003-005-AC

Dear Mr. Koerner:

Pursuant to Title V Air Construction Permit No. 0730003-005-AC, the City of Tallahassee (City) recently installed two General Electric LM6000 Turbine-Generator sets at the Arvah B. Hopkins Generating Station.

Combustion Turbine Unit Nos. HC3 (EU-031) and HC4 (EU-032) commenced initial startup on July 31, 2005, and September 27, 2005, respectively (*see attached regulatory notifications*).

Pursuant to the above referenced Title V Air Construction Permit, and Rule 62-213.420, Florida Administrative Code, an application for an operation permit must be submitted to the Florida Department of Environmental Protection (Department) within 180 days of commencing operation.

The City is requesting confirmation from the Department that since these two combustion turbine units were permitted concurrently and within the same Title V Air Construction Permit that the 180-day time clock begins when the last unit commences operation (i.e. September 27, 2005). Alternatively, the City is requesting an extension of time to submit the Title V Air Operation Permit Application for the above referenced combustion turbines until March 27, 2006.

Please do not hesitate to contact John Powell, Environmental Engineer at 891-8851, or myself at 891-8850, if you have any questions or require additional information.

Sincerely,

Jennette Curtis

Jennette Curtis
Environmental Services Administrator
Attachments

cc: Cynthia Barber, COT
Kevin Wailes, COT
Rob McGarrah, COT
Triveni Singh, COT
Phil Bucci, COT
John Powell, COT

City of Tallahassee
Your Own Utilities℠

300 South Adams Street, Tallahassee, Florida 32301, (850) 891-4YOU (4968), talgov.com

October 3, 2005 Certified Mail No.: 70031010000120674914

Air Resources Section
Northwest District Office
Florida Department of Environmental Protection
160 Governmental Center
Pensacola, Florida 32502-5794

Re: Notification of Initial Startup
Combustion Turbine HC4 (EU-032)
City of Tallahassee
Arvah B. Hopkins Generating Station - Facility I.D. No. 0730003

Dear Sir / Madam:

Pursuant to 40 CFR 60.7(a)(3) and Title V Air Construction Permit No. 0730003-005-AC, the City of Tallahassee is providing notification of the actual date of initial startup for the Arvah B. Hopkins Generating Station Combustion Turbine HC4 (EU-032). The actual ~~date of initial startup for purposes of 40 CFR 60.7(a)(3) was September 27, 2005.~~

Please do not hesitate to contact John Powell, Environmental Engineer at (850) 891-8851, or me at (850) 891-8850, if you have any questions or require additional information.

Sincerely,

Jennette Curtis

Jennette Curtis
Environmental Services Administrator

cc: FDEP Division of Air Resources Management, Tallahassee, FL
Cynthia Barber, COT
Kevin Wailes, COT
Rob McGarrah, COT
Triveni Singh, COT
Phil Bucci, COT
Cyrinda DeMontmollin, COT
John Powell, COT

City of Tallahassee
Your Own Utilities

August 5, 2005 Certified Mail No.: 70031010000120674723

Air Resources Section
Northwest District Office
Florida Department of Environmental Protection
160 Governmental Center
Pensacola, Florida 32502-5794

Re: Notification of Initial Startup
Combustion Turbine HC3 (EU-031)
City of Tallahassee
Arvah B. Hopkins Generating Station - Facility I.D. No. 0730003

Dear Sir / Madam:

Pursuant to 40 CFR 60.7(a)(3) and Title V Air Construction Permit No. 0730003-005-AC, the City of Tallahassee is providing notification of the actual date of initial startup for the Arvah B. Hopkins Generating Station Combustion Turbine HC3 (EU-031). The actual date of initial startup for purposes of 40 CFR 60.7(a)(3) was July 31, 2005.

Please do not hesitate to contact John Powell, Environmental Engineer at (850) 891-8851, or me at (850) 891-8850, if you have any questions or require additional information.

Sincerely,

Jennette Curtis

Jennette Curtis
Environmental Services Administrator

cc: FDEP Division of Air Resources Management, Tallahassee, FL
Cynthia Barber, COT
Kevin Wailes, COT
Rob McGarrah, COT
Triveni Singh, COT
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✓John Powell, COT