Memorandum

Florida Department of Environmental Protection

TO:	Joseph Kahn, Director, DARM
Through:	Trina L. Vielhauer, Chief, BAR
From:	aal A.A. Linero, P.E., PA/Cindy Mulkey South Permitting Section
DATE:	December 20, 2006
SUBJECT:	OUC Stanton Unit B – Nominal 285 MW coal-fueled ICCC DEP File No. 0950137-010-AC (PSD-FL-373, and PA 81-14SA3)

Attached is the final permit package for OUC Stanton Unit B. The project consists of a nominal 285 MW coal-fueled integrated gasification combined cycle (IGCC) electric utility steam generating unit.

Comments were received from EPA and Orange County during the 30-day comment period. EPA's comments have been addressed in the attached Final Determination to Issue a PSD Permit. Any outstanding issues raised by Orange County have been resolved in a Joint Stipulation filed by all involved parties.

The Joint Stipulation included a request for the ALJ to cancel the certification hearing and relinquish jurisdiction to DEP. This request was granted on October 31, 2006.

On December 15, 2006 the Certification Order authorizing the project was signed by Secretary Castille.

We recommend your approval of the attached Final Notice and Permit.

AAL/cem

Attachments

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Frederick F. Haddad, Jr., V.P. Power Resources
OUC/Southern Power Company – Orlando
Gasification, LLC.
5100 South Alafaya Trail
Orlando, Florida 32831

Curtis H. Stanton Energy Center
DEP File No. 0950137-010-AC
PSD-FL-373
IGCC Unit B
Orlando County

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Enclosed is the Final Permit, No. PSD-FL-373 (0950137-010-AC), for the construction of a nominal 285 MW coal fueled integrated gasification combined cycle electric utility steam generating unit at the existing Curtis H. Stanton Energy Center. The facility is located southeast of Orlando, in Orange County. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

for Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Permit) and all copies were sent electronically (with Received Receipt) before the close of business on 12/26/06 to the person(s) listed:

Frederick F. Haddad, Jr., OUC: fhaddad@ouc.com
Denise M. Stalls, OUC: dstalls@ouc.com
Randall E. Rush, Southern Company: rerush@southernco.com
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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) 12/26/06 (Date)

Department of
Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

PERMITTEE:

OUC/Southern Power Company – Orlando Gasification, LLC
5100 South Alafaya Trail
Orlando, Florida 32831

Authorized Representative:
Frederick F. Haddad, Jr., V.P. Power Resources

Curtis H. Stanton Energy Center	
IGCC Unit B	
Permit No.	PSD-FL-373
Project No.	0950137-010-AC
Siting No.	PA 81-14SA3
Expires:	July 31, 2010

PROJECT AND LOCATION

This permit authorizes the construction of a nominal 285 MW coal fueled integrated gasification combined cycle electric utility steam generating unit at the existing Curtis H. Stanton Energy Center. The facility is located southeast of Orlando, in Orange County. The project is a Commercial Demonstration Project receiving funds from the Department of Energy under the Clean Coal Power Initiative.

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Joseph Kahn, Director
Division of Air Resource Management

Date: 12/22/2006

FINAL DETERMINATION

OUC/SOUTHERN POWER COMPANY – ORLANDO GASIFICATION, LLC
CURTIS H. STANTON ENERGY CENTER
DEP FILE NO. 0950137-010-AC (PSD-FL-373)

On July 26, 2006 the Florida Department of Environmental Protection (Department) distributed an "Intent to Issue PSD Permit" to construct a nominal 285 megawatt coal-fueled integrated gasification combined cycle (IGCC) unit at the existing Curtis H. Stanton Energy Center near Orlando in Orange County. The project includes a nominal 160 MW General Electric 7F combustion turbine-electrical generator capable of firing synthesis gas (syngas); a supplementary-fired heat recovery steam generator (HRSG); a nominal 135 MW steam-electrical generator; a 205-foot stack; a mechanical draft cooling tower with drift eliminators; a gasification system including air blown coal gasification reactor/s (KBR Transport Gasifier), a multipoint ground flare, a 184-foot gasifier startup stack, and a coal and gasification ash storage and handling area.

The package included the Department's Draft Air Construction Permit, the "Intent to Issue PSD Permit," the "Technical Evaluation and Preliminary Determination," "Addendum to the Technical Evaluation and Preliminary Determination", and the "Public Notice of Intent to Issue PSD Permit." The Department sent copies of the package to various persons, agencies, and municipalities. Orlando Utilities Commission (OUC) published the Public Notice in *The Orlando Sentinel* on July 28, 2006 and provided to the Department the required proof of publication.

A Best Available Control Technology (BACT) determination was required for emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The Draft permit included BACT determinations for SO_2, CO and VOC. A BACT determination for nitrogen oxides (NO_X) was not required because of planned offsetting reduction at two existing units at the same location.

Consideration in making these determinations was given the fact that the gasification technology proposed is the first of its kind application of a dry, air-blown, low temperature Transport Gasifier for low rank coals that was partially funded by Department of Energy for funding under Round 2 of the Clean Coal Power Initiative. Some of the control technologies used are also first applications to an IGCC project. Additional consideration was given in accordance with Section 403.061(18), F.S., that states that the Department has the power and the duty to encourage and conduct studies, investigations, and research relating to pollution and its causes, effects, prevention, abatement, and control.

No requests for administrative hearings were received on the Notice of Intent to Issue.

Written comments were received during the 30-day public comment period from EPA on August 21, 2006 and from the Orange County Environmental Protection Division (EPD) on August 28, 2006. No comments were received from other agencies or the public regarding the Draft Air Construction Permit.

This project was also subject to the Site Certification process. On October 19, 2006, OUC/Southern Power Company-Orlando Gasification LLC, the Department, the County, the Florida Department of Transportation and the Florida Department of Community Affairs filed a Joint Stipulation including a request for cancellation of the certification hearing, and relinquishing of jurisdiction to DEP by the Administrative Law Judge. This request was granted on October 31, 2006.

On December 15, 2006 the Site Certification Order was issued by the Department. The Department is required to take final action on the PSD Permit Application and the Draft Permit within 30 days following the final Certification Order.

The County and OUC will work jointly on several projects outside the scope of this review. They include various transportation and renewable energy such as a photovoltaic initiative within the County.

The County's comments regarding the Draft Permit are in the nature of observations, aspirations and preferences regarding the following items. They can be reviewed at:

http://www.dep.state.fl.us/Air/permitting/construction/oucsouthern.htm.

The Department reviewed the County's comments and believes that the project will ultimately be able to actually achieve lower emissions for most of the pollutants than the values given in the permit. Some freedom and flexibility was provided given the first applications of the gasification and control processes that will be researched and proven during the course of the demonstration. The project will be the first known application of oxidation catalyst at an IGCC plant and the first application of SCR technology at an IGCC power plant in the United States. It will also be the first project to use carbon adsorption for mercury (Hg) control at an IGCC power project. These facts speak to the County's concerns while providing the applicant the needed flexibility for this first application of the Transport Gasifier.

EPA's comments are summarized below followed by the Department's responses. They may be viewed in their entirety at the mentioned website. Any additions to permit conditions are double underlined and deletions are indicated by double strike-through.

Comment 1

EPA requested "in future when an initial draft permit is followed by a revised draft permit, we would prefer that FDEP issue a single revised technical evaluation to accompany the revised draft permit".

Response

The Department concurs and will issue an updated Technical Evaluation rather than an addendum on future projects.

Comment 2

The draft permit contains a requirement for the installation and operation of an oxidation catalyst for a period of two years. OUC is allowed to "at its sole discretion" remove the catalyst at any time following the two-year period. EPA recommends that OUC be required to obtain approval from DEP prior to removal of the catalyst.

Response

Considering the research and demonstration nature of this project, it was decided to allow catalyst removal after two years at the discretion of OUC. It is possible OUC will maintain the catalyst on a permanent basis following the two year trial. The Department is confident that OUC will make a prudent environmental and economic decision at the time. The Department will not add a requirement for authorization prior to removal. However, OUC has agreed to additional requirements for notification of removal and submission of a technical report describing the demonstration of the CO catalyst.

The following change will be made to Section III, Subsection A, Condition 9c:

c. *Oxidation Catalyst*: Between 21 and 27 months following the completion of all initial compliance testing required under this permit, the permittee shall install, operate, and maintain an oxidation catalyst designed and intended to reduce CO emissions from the combustion turbine when firing natural gas, synthesis gas, or a combination thereof to 4.1 ppmvd @ 15% O_2. Two years following original installation of this oxidation catalyst, permittee shall, in its sole discretion, become authorized to remove the catalyst at any time. Permittee shall only remove the catalyst prior to the end of this two year period,if the project representative for the Department of Energy expressly concurs with a recommendation from the permittee, which recommendation shall be provided concurrently to the Department, for its removal based on the inability to achieve Department of Energy demonstration objectives with the CO catalyst remaining in place, or based on serious, actual maintenance problems associated with the catalyst installation. Permittee shall maintain records on performance of the catalyst in accordance with any DOE demonstration obligations. Upon removal of the initial CO catalyst, the permittee shall notify the Department and shall return a sample of the catalyst to the vendor for evaluation of relevant commercial properties and use its best efforts to provide the Department with subsequent evaluation results. Within 6 months of removing the initial CO catalyst, if such catalyst is not immediately replaced, permittee shall submit to the Department a technical report describing the demonstration of the CO catalyst on this unit.

Comment 3

The Addendum to the Technical Evaluation includes a statement that the "oxidation catalyst will be installed and maintained for a period of two years to reduce CO emissions to 4.1 ppmvd". However, a CO emissions limit in Condition 16 that imposes a 4.1 limit when the oxidation catalyst is in use was not found.

Response

There are CO limits of 20.5 and 15.8 ppmvd @ 15% O_2, while firing syngas, with duct burners and without the duct burners respectively. Condition 9.c. of the permit (included in Comment 1 Response above) requires that the permittee installs, operates, and maintains an oxidation catalyst designed and intended to reduce CO emissions from the combustion turbine when firing natural gas, synthesis gas, or a combination thereof to 4.1 ppmvd @ 15% O_2. The Department and the applicant's *expectation* is that CO emissions will be reduced to 4.1 ppmvd.

Comment 4

EPA recommends clarification of Section III, subsection A, condition 15.a. regarding applicability of NO_X emissions limits of the permit.

Response

The NO_X limits in the permit are for the purpose of avoiding PSD preconstruction review and are not BACT-based limits. The Department agrees with EPA's recommendation and will make the following change to Section III, Subsection B, Condition 15.a. of the permit:

15. Emission Standards: Emissions from the turbine/HRSG system shall not exceed the following standards.

    a. For purposes of meeting the BACT and PSD preconstruction review avoidance limits of this subsection, an hour in which a synthesis gas/natural gas fuel mixture is fired, is subject to the ~~BACT~~ limit for natural gas when the mixture contains greater than 75% natural gas (by heat input), and subject to the ~~BACT~~ limit for synthesis gas when the mixture contains 75% or less natural gas (by heat input) for that hour. Any hour in which both synthesis gas and natural gas are combusted in the combustion turbine due to fuel switching, shall be subject to the limits for synthesis gas firing.

Comment 5

The Stanton Unit B IGCC permit includes a NO_X emissions cap for Stanton Units 1 and 2. EPA commented on their expectation that the conditions of the cap will appear in a permit specific to Stanton Units 1 and 2.

Response

OUC recently applied for the first in a series of measures to reduce NO_X emissions on Units 1 and 2 to the required levels of the permitted cap. Specific conditions of the NO_X cap have been incorporated into the draft permit (final pending). Such conditions will also be incorporated in the next revision or renewal of the facility Title V Operation Permit.

Comment 6

EPA recommends removal system types, if known, be specifically identified for mercury, sulfur and ammonia.

Response

The mercury system has been described in general terms as a carbon adsorption unit similar to the installation at the Eastman IGCC facility in Kingsport, Tennessee. The Department investigated the ability of Calgon Carbon to quote such a system for a transport gasifier and reviewed published literature regarding the capabilities of UOP.

Most commercial proposals of sulfur removal systems for IGCC projects specify Selexol, Rectisol, or methyl diethyl amine (MDEA) scrubbing. Southern/OUC recently advised the Department that it will actually use the recently demonstrated CrystaSulf technology that directly converts hydrogen sulfide to elemental sulfur.

The applicant described the removal process in general terms as a water scrubbing system. More recently the applicant advised that Kellogg Brown and Root (the developers of the Transport Gasifier) designs and engineers many of the commercial ammonia scrubbing systems (such as in the refining industry). KBR will also design and engineer the water scrubbing system for this project.

The Department has reasonable assurance that the above technologies exist to meet the permitted emissions values. Based on the research nature of this first-of-a-kind demonstration it is possible that the applicant could consider other Hg, sulfur and ammonia removal concepts depending on the outcome of the planned demonstrations. The Department will leave the technology descriptions in general terms for this specific demonstration project and provide the project with the flexibility to make changes should they become necessary for unforeseen circumstance. This is part of the consideration given under Section 403.061(18) of the Florida Statutes.

Comment 7

Condition 14 allows exhaust gases to be directed to the startup stack only during "initial startup". Does this not include other startups, for example following a prolonged outage?

Response

The condition was intended for not only "initial" startup, but for any startup of the gasification system. The following changes will be made to Section III, Subsection A, Condition 14:

14. Methods of Operation of the Gasifiers: Subject to the restrictions and requirements of this permit, the gasification island may operate under the following methods of operation.

    a. *~~Initial~~ Startup:* During startup of the gasification island, gasifier gas may be vented to the gasifier startup stack after passing through the particulate filtration system. As soon as possible, upon reaching a reducing atmosphere within the gasifier, the exhaust synthesis gas shall be directed to the flare and not to the startup stack. At no time, other than ~~initial~~ startup, shall the exhaust gases be directed to the startup stack.

Comment 8

The phrase "for the life of the permit" is used in condition 16.a. of the permit. EPA suggests deleting the phrase because PSD construction permits do not expire.

Response

The Department concurs and Section III, Subsection A, Condition 16.a. will be changed as follows:

16. Carbon Monoxide (CO): Emissions of CO from the CT/HRSG system shall not exceed the following BACT limits on a 24-hr rolling average as measured by the required CEMS and during the required stack tests.

    a. *While firing natural gas CO emissions shall not exceed:*

       Duct burners on –27.2 ppmvd @ 15% O_2 and 138.0 lb/hr

       Duct burners off – 20.5 ppmvd @ 15% O_2 and 79.0 lb/hr

       However, beginning with the 10th calendar year after the completion of the initial compliance tests, and for each calendar year thereafter, if, excluding startup, the total natural gas heat input to the combustion turbine for the prior 48 months exceeds 50% of the total heat input to the combustion turbine for that period, then CO emissions thereafter ~~for the life of the permit~~ shall not exceed:

       Duct burners on – 4.1 ppmvd @ 15% O_2 and 20.8 lb/hr

       Duct burners off – 4.1 ppmvd @ 15% O_2 and 15.8 lb/hr

Comment 9

EPA refers to a reference to the Technical Evaluation in Appendix BD of the permit. EPA asks whether the Addendum to the Technical Evaluation should also be referenced.

Response

Appendix BD contains the "final" BACT determination and emissions limits. The reference to the Technical Evaluation is unnecessary and has been removed.

The final decision by the Department is to issue the permit with the changes noted.

PSD: The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a "fossil fuel-fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the facility categories listed at 62-210.200(definitions, Major Stationary Source) with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 F.A.C., Prevention of Significant Deterioration (PSD).

NSPS: The following New Source Performance Standards of 40 CFR 60 may be potentially applicable to the IGCC Unit B as described in Section III, Subsection A, Federal Requirements of this permit.

- Subpart Da (Standards of Performance for Electric Utility Steam Generating Units For Which Construction is Commenced After September 18, 1978).
- Subpart KKKK (Standards of Performance for Stationary Combustion Turbines).

The coal storage and handling facilities of Unit B are subject to Subpart Y (Standards of Performance for Coal Preparation Plants).

NESHAP: The facility is a "Major Source" of HAPs and Unit B is subject to the applicable requirements of 40 CFR 63, Subpart YYYY (National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines) as described in Section III, Subsection A, Federal Requirements of this permit.

CAIR: As an electric generating unit, Unit B may be subject to the Clean Air Interstate Rule pending the finalization of DEP rules.

CAMR: Unit B is a new coal-fired power plant and may be subject to the Clean Air Mercury Rule pending finalization of DEP rules.

Siting: The facility is a steam electrical generating plant and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

PERMITTING AUTHORITY

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

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department of Environmental Protection Central District, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A	NSPS and NESHAP Subparts A, Identification of General Provisions
Appendix BD	Final BACT Determinations and Emissions Standards
Appendix Da	NSPS Subpart Da Requirements for Electric Utility Steam Generating Units
Appendix GC	General Conditions
Appendix KKKK	NSPS Subpart KKKK Requirements for Stationary Combustion Turbines

Appendix SC	Standard Conditions
Appendix Y	NSPS Subpart Y Requirements for Coal Preparation Plants
Appendix YYYY	NESHAP Subpart YYYY Standard for HAPs for Stationary Combustion Gas Turbines

RELEVANT DOCUMENTS:

The documents listed below are not a part of this permit, however they are specifically related to this permitting action and are on file with the Department.

- February 17, 2006: Received Site Certification Application (SCA) including PSD application.
- April 5, 2006: Sent Sufficiency Issues to DEP Siting Coordination Office (SCO).
- April 10, 2006: SCA determined to be Insufficient by SCO.
- May 8, 2006: Received Sufficiency Responses from Applicant.
- May 26, 2006: Sent Status Letter on Sufficiency Responses.
- July 26, 2006: Intent to Issue PSD Permit distributed.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

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

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 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 the Title 40, Parts 51, 52, 60, 63, 72, 73, and 75 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.]

3. Construction and Expiration: Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

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

5. Source Obligation.

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

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

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

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

7. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

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

A. Unit B Integrated Gasification Combined Cycle (EU 030)

The specific conditions of this subsection apply to the following emissions unit after construction is complete.

E.U. ID	Emission Unit Description
030	Unit B Integrated Gasification Combined Cycle – Consists of one General Electric PG7241 FA gas turbine electrical generator (nominal 160 MW) equipped with evaporative inlet air cooling, a heat recovery steam generator (HRSG) with supplemental duct firing, a HRSG stack, a steam turbine electrical generator (nominal 135 MW), and the gasification system associated with one gasifier startup stack.

The integrated gasification combined cycle unit contains the following emission points.

Point ID	Emissions Point Description
GCC-1	CT/HRSG Stack
GCC-2	Gasifier Startup Stack

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: A determination of the Best Available Control Technology (BACT) was made for carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOCs). [Rule 62-210.200 (BACT), F.A.C.]
2. NO_X Emissions Cap: An emissions cap on Units 1 and 2 was taken in order for the project to "net out" with respect to NO_X emissions, thus avoiding a BACT determination for nitrogen oxides.
3. NSPS Requirements: This unit may be subject to the subparts of 40 CFR 60, listed and as described below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that the BACT emissions performance requirements are as stringent as or more stringent than the limits imposed by the applicable NSPS provisions for SO_2, and PM. Some separate reporting and monitoring may be required by the individual subparts.
   a. The Unit is subject to **Subpart A, General Provisions**, including:
      - 40 CFR 60.7, Notification and Record Keeping
      - 40 CFR 60.8, Performance Tests
      - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
      - 40 CFR 60.12, Circumvention
      - 40 CFR 60.13, Monitoring Requirements
      - 40 CFR 60.19, General Notification and Reporting Requirements

   b. **Subpart Da, Standards of Performance for Electric Utility Steam Generating Units.** These provisions include standards for duct burners and certain heat recovery steam generators and associated stationary combustion turbines. Subpart Da may be applicable to the new IGCC Unit B as described in Section III, Subsection A, Federal Requirements of this permit.

   c. **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** These provisions include standards for stationary combustion turbines constructed after February 18, 2005. Subpart KKKK may be applicable to the new IGCC Unit B as described in Section III, Subsection A, Federal Requirements of this permit.

4. NESHAP Requirements: The combustion turbine is subject to 40 CFR 63, Subpart A, Identification of General Provisions and 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines as described in Section III, Subsection A, Federal Requirements of this permit.

EQUIPMENT DESCRIPTION

5. Combustion Turbine: The permittee is authorized to install, tune, operate, and maintain one General Electric Model PG7241FA gas turbine-electrical generator set with a nominal generating capacity of 160 MW. The combustion turbine will be equipped with GE's diffusion flame multinozzle quiet combustor (MNQC), and an inlet air filtration system with evaporative coolers. The combustion turbine will be designed for operation in an IGCC mode, will have dual-fuel capability and shall be designed for a maximum heat input rate of 1,942 mmBtu per hour when firing natural gas and 1,818 mmBtu per hour when firing syngas (based on a compressor inlet air temperature of 20° F, the higher heating value (HHV) of the fuel, and 100% load). Heat input rates will vary depending upon gas 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. [Application; Design]

6. HRSG: The permittee is authorized to install, operate, and maintain one heat recovery steam generator (HRSG) with a HRSG exhaust stack. The HRSG shall be designed to recover heat energy from the gas turbine and deliver steam to the steam turbine electrical generator. The HRSG will be equipped with supplemental gas-fired duct burners. The duct burners shall be designed for a maximum heat input rate of 531.5 mmBtu per hour based on the higher heating value (HHV) of natural gas. [Application; Design]

7. Generating Capacity: Unit B will have a nominal electrical generating capacity of 285 MW (net) when firing syngas and 310 MW when firing natural gas (duct burners operational).

8. Gasification System: The permittee is authorized to install, operate, and maintain a gasification system, consisting of air blown gasifier/s and one startup stack, for the production of synthesis gas to be fired in the combustion turbine. The gasification system includes the transport gasifier/s, a high temperature syngas cooler, a high temperature high pressure filtration system, a low temperature gas cooling and mercury removal system, a sulfur removal and recovery system, and a sour water treatment and ammonia recovery system. The gasification system shall be designed for a maximum total gasification heat input rate of 2,397 mmBtu per hour (based on an ambient air temperature of 20° F, the higher heating value (HHV) of the fuel, and 100% load). [Application; Design].

CONTROL TECHNOLOGY

9. Combustion Turbine/HRSG: The following pollution control equipment shall be installed and operated as specified below:

   a. *Steam Injection*: The permittee shall install, operate, and maintain a steam injection system to reduce NO_X emissions from the combustion turbine when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine, the steam injection system shall be tuned to achieve permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

b. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from the combustion turbine when firing natural gas, synthesis gas, or a combination thereof. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to meet the permitted levels of NO_X and NH_3 emissions.

   Ammonia Storage: In accordance with 40 CFR 68.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

c. *Oxidation Catalyst*: Between 21 and 27 months following the completion of all initial compliance testing required under this permit, the permittee shall install, operate, and maintain an oxidation catalyst designed and intended to reduce CO emissions from the combustion turbine when firing natural gas, synthesis gas, or a combination thereof to 4.1 ppmvd @ 15% O_2. Two years following original installation of this oxidation catalyst, permittee shall, in its sole discretion, become authorized to remove the catalyst at any time. Permittee shall only remove the catalyst prior to the end of this two year period if the project representative for the Department of Energy expressly concurs with a recommendation from the permittee, which recommendation shall be provided concurrently to the Department, for its removal based on the inability to achieve Department of Energy demonstration objectives with the CO catalyst remaining in place, or based on serious, actual maintenance problems associated with the catalyst installation. Permittee shall maintain records on performance of the catalyst in accordance with any DOE demonstration obligations. Upon removal of the initial CO catalyst, the permittee shall notify the Department and shall return a sample of the catalyst to the vendor for evaluation of relevant commercial properties and use its best efforts to provide the Department with subsequent evaluation results. Within 6 months of removing the initial CO catalyst, if such catalyst is not immediately replaced, permittee shall submit to the Department a technical report describing the demonstration of the CO catalyst on this unit.

[Design; Rules 62-210.200(PTE, and BACT), 62-210.650, 62-212.400(PSD), F.A.C.; Chapter 403.061, F.S.]

10. Gasification System: The following technologies shall be installed and operated for each gasifier train for treatment of the synthesis gas stream prior to combustion in the combustion turbine.

   a. *Particulate Filtration System*: The permittee shall install, operate, and maintain a high temperature/high pressure (HTHP) filtration system for the removal of particulate matter from the synthesis gas in order to achieve the permitted levels of particulate matter emissions from the CT/HRSG system.

   b. *Mercury Removal System*: The permittee shall install, operate, and maintain a mercury removal system to remove a sufficient amount of mercury from the synthesis gas stream to achieve the permitted levels of mercury emissions from the CT/HRSG system.

   c. *Sulfur Removal System*: The permittee shall install, operate, and maintain a sulfur removal system to remove a sufficient amount of sulfur from the synthesis gas stream to achieve the permitted levels of SO_2 and H_2SO_4 emissions from the CT/HRSG system.

   d. *Ammonia Recovery*: The permittee shall install, operate, and maintain an ammonia removal system to remove a sufficient amount of ammonia from the synthesis gas stream to help achieve the permitted levels of NO_X.

   Ammonia Storage: In accordance with 40 CFR 68.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

   [Design; Rule 62-212.400(PSD), F.A.C.]

PERFORMANCE REQUIREMENTS

11. Hours of Operation: The gasification system and/or gas turbine may operate throughout the year (8,760 hours per year). Restrictions on individual methods of operation are specified in separate conditions. [Rules 62-210.200(PTE, and BACT) and 62-212.400 (PSD), F.A.C.]

12. Authorized Fuels:

    a. *Synthesis Gas* - The combustion turbine may fire synthesis gas produced in the gasification system.

    b. *Natural Gas* -The combustion turbine may fire natural gas which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. Only natural gas shall be fired in the duct burners, and used for initial startup of the transport gasifier/s.

    c. *Synthesis Gas/Natural Gas Combination* – The combustion turbine may fire a synthesis gas/natural gas mixture. An hour in which a synthesis gas/natural gas fuel mixture is fired, is subject to the BACT limits for natural gas when the mixture contains greater than 75% natural gas (by heat input), and subject to the BACT limits for synthesis gas when the mixture contains 75% or less natural gas (by heat input) for that hour.

    d. *Coal* – When burning synthesis gas in the combustion turbine, coal shall be processed in the gasification island.

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

13. Methods of Operation of the Combustion Turbine: Subject to the restrictions and requirements of this permit, the gas turbine may operate under the following methods of operation.

    a. *Combined Cycle Operation*: The combustion turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall, to the extent practicable (considering availability and reliability of the unit), be on line and functioning properly during combined cycle operation, or when the HRSG is producing steam. The permittee shall keep records documenting the duration and reason for any period when the SCR system is not in operation. These records shall be made available to the Department upon request.

    b. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging."

    c. *Duct Firing*: The HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power.

    [Application; Rules 62-210.200 (PTE, and BACT), 62-210.650, and 62-212.400 (PSD), F.A.C.]

14. Methods of Operation of the Gasifiers: Subject to the restrictions and requirements of this permit, the gasification island may operate under the following methods of operation.

    a. *Startup:* During startup of the gasification island, gasifier gas may be vented to the gasifier startup stack after passing through the particulate filtration system. As soon as possible, upon reaching a reducing atmosphere within the gasifier, the exhaust synthesis gas shall be directed to the flare and not to the startup stack. At no time, other than startup, shall the exhaust gases be directed to the startup stack.

b. *Synthesis Gas Flaring:* Once the gasifiers reach a reducing atmosphere, synthesis gas shall be directed through the gas clean-up processes to the flare. Flaring during startup shall take place only until there is sufficient synthesis gas production to support operation of the combustion turbine. Operation of the combustion turbine may be accomplished by mixing the synthesis gas with natural gas. Synthesis gas may be directed to the flares during upset conditions such as trips of the CT/HRSG system to allow safe release of the pressurized gas.

c. *Integrated Operation:* The gasification system may operate to produce synthesis gas for combustion in the combustion turbine. All control equipment/technologies constructed to treat the gas stream prior to combustion of the synthesis gas in the combustion turbine shall be on line and functioning properly, in accordance with the specifications of the manufacturers, during the integrated operation of the gasification and CT/HRSG systems.

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

EMISSIONS AND TESTING REQUIREMENTS

15. Emission Standards: Emissions from the turbine/HRSG system shall not exceed the following standards.

Best Available Control Technology (BACT) – Rule 62-210.200, F.A.C.			
While Firing Natural Gas[a]			
Pollutant	Stack Test, 3-Run Average		CEMS Average
	ppmvd @ 15% O_2	lb/hr[c]	
CO (DB)[f]	27.2/4.1	138.0/20.8	24-hr rolling
CO (w/o DB)[f]	20.5/4.1	79.0/15.8	
VOC (DB)	6.5	19.0	N/A
VOC (w/o DB)	2.4	5.3	
SO_2[b]	2.0 gr S/100 SCF of gas		N/A
SAM[b]	2.0 gr S/100 SCF of gas		N/A
PM/PM_{10}[c]	2.0 gr S/100 SCF of gas		N/A
	10 % opacity, 6-minute block average		
Ammonia[d]	5.0	N/A	N/A
While Firing Synthesis Gas[a]			
CO (DB)	20.5	140.5	24-hr rolling
CO (w/o DB)	15.8	90.7	
VOC (DB)	4.6	17.9	N/A
VOC (w/o DB)	2.4	7.9	
SO_2[b]	2.7	35.5	30-day rolling
PM/PM_{10}	Compliance with SO_2/CO standards		N/A
	10 % opacity, 6-minute block average		
SAM[b]	Compliance with SO_2		N/A
Ammonia[d]	5.0	N/A	N/A

PSD Preconstruction Review Avoidance – Rule 62-212.400(2)(a), F.A.C.				
Pollutant	Fuel	ppmvd @ 15% O_2	TPY	CEMS Average
NO_X	Natural Gas	15.0	N/A	30-day rolling
	Syngas	20.0		30-day rolling
	Natural Gas/Syngas	N/A	1,006	12-month rolling
Mercury	Natural Gas/Syngas	10 x 10^{-6} lb/MWh	29 lb/yr	12-month rolling

a. For purposes of meeting the BACT and PSD preconstruction review avoidance limits of this subsection, an hour in which a synthesis gas/natural gas fuel mixture is fired, is subject to the limit for natural gas when the mixture contains greater than 75% natural gas (by heat input), and subject to the limit for synthesis gas when the mixture contains 75% or less natural gas (by heat input) for that hour. Any hour in which both synthesis gas and natural gas are combusted in the combustion turbine due to fuel switching, shall be subject to the limits for synthesis gas firing.

b. The fuel sulfur specifications, established in Condition 12 of this subsection, effectively limit the potential emissions of SO_2 and SAM from the combustion turbine while firing natural gas and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 49 of this subsection. BACT for SO_2 while firing synthesis gas has been determined as 2.7 ppmvd and 35.5 lb/hr. Compliance with the SO_2 limit effectively limits the potential emissions of SAM while firing synthesis gas.

c. The fuel sulfur specifications for natural gas and the SO_2 standard for syngas, combined with the efficient combustion design and operation of the combustion turbine represent BACT for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion.

d. The SCR system shall be designed and operated for an ammonia slip limit of no more than 5 ppmvd corrected to 15% O_2 based on the average of three test runs. Notwithstanding this provision, ammonia slip may exceed 5 ppmvd but may not exceed 10 ppmvd corrected to 15% O_2 when the SCR system is voluntarily operated to reduce NOx emissions below 10 ppmvd.

e. Mass emission rate standards and concentrations are based on 100 percent full load operation, an ambient temperature of 70° F, and using the HHV of the fuel. The mass emission rate may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

f. These emission standards for CO when firing natural gas shall be determined in accordance with Condition 16.a of this subsection.

{Permitting Note: The above emissions standards effectively limit annual potential emissions from the combustion turbine/HRSG system to: 615 tons/year of CO, 83 tons/year of VOC, 155 tons/year of SO_2, less than 24 tons/year of SAM, and less than 156 tons/year of PM/PM_{10}.}

[Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

16. Carbon Monoxide (CO): Emissions of CO from the CT/HRSG system shall not exceed the following BACT limits on a 24-hr rolling average as measured by the required CEMS and during the required stack tests.

   a. *While firing natural gas CO emissions shall not exceed:*

      Duct burners on –27.2 ppmvd @ 15% O_2 and 138.0 lb/hr

      Duct burners off – 20.5 ppmvd @ 15% O_2 and 79.0 lb/hr

However, beginning with the 10^{th} calendar year after the completion of the initial compliance tests, and for each calendar year thereafter, if, excluding startup, the total natural gas heat input to the combustion turbine for the prior 48 months exceeds 50% of the total heat input to the combustion turbine for that period, then CO emissions thereafter shall not exceed:

Duct burners on – 4.1 ppmvd @ 15% O_2 and 20.8 lb/hr

Duct burners off – 4.1 ppmvd @ 15% O_2 and 15.8 lb/hr

b. *While firing synthesis gas CO emissions shall not exceed:*

Duct burners on –20.5 ppmvd @ 15% O_2 and 140.5 lb/hr

Duct burners off – 15.8 ppmvd @ 15% O_2 and 90.7 lb/hr

[Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

17. Volatile Organic Compounds (VOCs): Emissions of VOC from the CT/HRSG system shall not exceed the following standards as determined by data collected during the required stack tests:

a. *While firing natural gas, VOC emissions shall not exceed:*

Duct burners on –6.5 ppmvd @ 15% O_2 and 19.0 lb/hr

Duct burners off –2.4 ppmvd @ 15% O_2 and 5.3 lb/hr

b. *While firing synthesis gas, VOC emissions shall not exceed:*

Duct burners on – 4.6 ppmvd @ 15% O_2 and 17.9 lb/hr

Duct burners off – 2.4 ppmvd @ 15% O_2 and 7.9 lb/hr

[Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

18. Sulfur Dioxide (SO_2):

a. *While firing natural gas*:

The fuel sulfur specifications, established in Condition 12 of this subsection, of 2.0 grains per 100 standard cubic feet effectively limit the potential emissions of SO_2 while firing natural gas from the combustion turbine.

b. *While firing synthesis gas*: Emissions of SO_2 from the CT/HRSG system shall not exceed 2.7 ppmvd @ 15% O_2 and 35.5 lb/hr on a 30-day rolling average as measured by the required CEMS and during the required stack tests.

[Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

19. Sulfuric Acid Mist (SAM, H_2SO_4): Sulfuric acid mist is effectively limited by the fuel sulfur specifications and the sulfur dioxide limits while burning natural gas and synthesis gas respectively. These requirements represent BACT for this pollutant. [Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

20. Particulate Matter (PM/PM_{10}):

a. *While burning natural gas*:

The fuel sulfur specifications, established in Condition 12 of this subsection, combined with the efficient combustion, design, and operation of the combustion turbine represent BACT for PM/PM10 emissions while firing natural gas. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Visible emissions shall not exceed 10 % opacity as observed during the required visible emissions tests.

b. *While burning synthesis gas*:

The SO_2 standard for synthesis gas, combined with the efficient combustion design and operation of the combustion turbine represent BACT for PM/PM_{10} emissions. Compliance with the SO_2 and CO standards, and visible emissions standard shall serve as indicators of good combustion. Visible emissions shall not exceed 10 % opacity as observed during the required visible emissions tests. Results from the particulate matter stack tests, as required in Conditions 30 of this subsection, shall be reported to the compliance authority.

{Permitting Note: The SO_2 limit of 2.7 ppm is approximately equal to 0.019 lb SO_2/mmBtu of synthesis gas which is below the sulfur dioxide fuel specification of 60.49Da(u)(2)}

[Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C, 40 CFR 60.49, and Chapter 403.061(18), F.S.]

21. Ammonia: Ammonia slip shall not exceed 5 ppmvd @ 15% O_2 as determined by data collected during the required stack tests, except as provided in Condition 15, note d of this subsection.

22. Mercury (Hg): Emissions of mercury from the CT/HRSG system shall not exceed 10 x 10^{-6} lb/MWh on a 12 month rolling average based on methods and requirements as described in 40 CFR 60.45Da(b) and 60.50Da(g).
[Rules 62-4.070(3), and 62-212.400(12)(PSD Avoidance), F.A.C, and 40 CFR 60.45Da (b) and 60.50Da(g)]

23. Nitrogen Oxides (NO_X): Emissions of NO_X from the CT/HRSG system shall not exceed the following standards as measured by the required CEMS for the averaging period specified, and as measured during the required stack tests.

    a. *While burning natural gas*:

    15 ppmvd @ 15% O_2 on a rolling 30-day average

    b. *While burning synthesis gas:*

    20.0 ppmvd @ 15% O_2 on a rolling 30-day average

[Rules 62-4.070(3), and 62-212.400(12)(PSD Avoidance), F.A.C, Applicant Request, and 40 CFR 60.4325]

24. NO_X Emissions Cap:

    a. *Existing Units 1 and 2*: The combined NO_X emissions from existing coal fired boiler steam electric generating Stanton Unit 1 and Stanton Unit 2 shall not exceed 8,300 tons per year on a 12-month rolling total beginning the first month of first fire of Unit B and thereafter. Total NO_X emissions shall be based on data collected from the Unit 1 and Unit 2 NO_X CEMS and the rolling 12-month total from each unit shall be computed in accordance with Condition 46 of this subsection.

    b. *New Unit B*: Total NO_X emissions from the new Unit B CT/HRSG stack, gasifier startup stack, and flare shall not exceed 1,006 tons on a 12-month rolling total. Total NO_X emissions from the CT/HRSG stack shall be based on data collected from the required NO_X CEMS and computed in accordance with Condition 46 of this subsection. Total NO_X emissions from the flare and gasifier startup stack shall be estimated in accordance with 62-210.370, F.A.C.

    c. If the combined NO_X emissions from Units 1 and 2 exceed 8,300 tons during any 12-month period, and/or the total NO_X emissions from Unit B exceeds 1,006 tons during any 12-month period, Unit B shall be subject to PSD preconstruction review at that time, and a determination of BACT for NO_X shall be made.

d. For purposes of meeting the NO_X emissions caps, annual emission of NO_X from existing Units 1 and 2, and Unit B shall be calculated without the Allowable Data Exclusions of Condition 37 of this subsection. All valid hours of data (including startup and shutdown) must be included in the rolling 12-month totals. Also, the data substitution procedures of Part 75 for missing data shall not be used in these calculations.

[62-210.200 (net emissions increase), 62-210.370 (emissions computation), and 62-212.400(12) (Source Obligation), F.A.C.]

{Permitting Note: This project did not trigger PSD for NO_X due to a NO_X emissions cap taken on existing coal fired boiler steam electric generating Unit 1 and Unit 2. The above conditions establish the requirements for meeting the NO_X emission limitations for purposes of avoiding PSD preconstruction review. These requirements in no way supersede any federal requirement of the applicable NSPS or NESHAP provisions.}

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

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

Method	Description of Method and Comments
1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content. Methods shall be performed as necessary to support other methods.
5	Determination of Particulate Emissions. The minimum sample volume shall be 30 dry standard cubic feet.
6C	Determination of SO2 Emissions (Instrumental).
7E	Determination of NOx Emissions (Instrumental).
9	Visual Determination of Opacity
10	Measurement of Carbon Monoxide Emissions (Instrumental). The method shall be based on a continuous sampling train.
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization – Instrumental)
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source • This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C.
[Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

27. Testing Requirements: Initial tests shall be conducted between 90% and 100% of permitted capacity; otherwise, this permit shall be modified to reflect the true maximum capacity as constructed. Subsequent annual tests shall be conducted between 90% and 100% of permitted capacity in accordance with the requirements of Rule 62-297.310(2), F.A.C. Tests shall be conducted for each required pollutant when firing natural gas, when firing syngas, and when using the duct burners while firing each fuel in the CT. For each run during tests for visible emissions and ammonia slip, emissions of CO and NO_X recorded by the

CEMS shall also be reported. Particulate matter testing and reporting shall include front and back half catches. Data collected from the reference method during the required CEMS quality assurance RATA tests may substitute for annual compliance tests for those pollutants, provided the owner or operator indicates this intent in the submitted test protocol, and obtains approval prior to testing. [Rule 62-297.310(7)(a), F.A.C.; 40 CFR 60.8]

28. Initial Compliance Demonstration:

    a. *Natural Gas:* Initial compliance stack tests shall be conducted within 60 days after achieving the maximum production rate on natural gas, but not later than 180 days after the initial startup on natural gas. In accordance with the test methods specified in this permit, the combustion turbine shall be tested to demonstrate initial compliance with the emission standards for CO, SO_2, NO_X, Hg, ammonia slip, VOC, and visible emissions. The permittee shall provide the Compliance Authority with any other initial emissions performance tests conducted to satisfy vendor guarantees.

    b. *Synthesis Gas*: Initial compliance stack tests shall be conducted within 60 days after achieving the maximum heat input to the combustion turbine on synthesis gas, but not later than 180 days after the initial operation of the combustion turbine on synthesis gas. In accordance with the test methods specified in this permit, the combustion turbine shall be tested to demonstrate initial compliance with the emission standards for CO, SO_2, NO_X, Hg, ammonia slip, VOC, and visible emissions. The permittee shall provide the Compliance Authority with any other initial emissions performance tests conducted to satisfy vendor guarantees.

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

29. Subsequent Compliance Testing: Annual compliance stack tests for CO, SO_2, NO_X, ammonia slip, VOC, and visible emissions shall be conducted during each federal fiscal year (October 1st, to September 30th). Annual testing to determine VOC emissions, visible emissions, and ammonia slip shall be conducted while firing the primary fuel. Data collected from the reference method during the CO, SO_2, and NO_X CEMS quality assurance RATA tests may be used to satisfy the annual compliance stack test requirements for these pollutants, provided the owner or operator indicates this intent in the submitted test protocol, and obtains approval prior to testing. Additional testing for CO and NO_X may be required following catalyst replacement. If normal operation on natural gas is less than 400 hours per year, then subsequent compliance testing on natural gas is not required for that year. If normal operation on natural gas exceeds 400 hours per year, the Department may require compliance testing for visible emissions, ammonia slip, and VOC emissions while firing natural gas.
    [Rules 62-4.070, 62-210.200(BACT), and 62-297.310(7)(a)4, F.A.C., and 40 CFR 60.50Da]

30. Additional Testing: Concurrent with initial and subsequent compliance testing, particulate matter testing (front and back half) shall be conducted while firing synthesis gas and the results shall be reported to the Department.

31. Continuous Compliance: Continuous compliance with the permit standards for emissions of CO, NO_X, and SO_2 shall be demonstrated with data collected from the required continuous monitoring systems. Compliance with the permit standards for mercury shall be demonstrated with data collected in accordance with Condition 41. [Rules 62-4.070, and 62-210.200(BACT), F.A.C., 40 CFR 60.50Da]

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

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No 15 of this subsection. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

33. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of the gas turbine, HRSG, gasification system, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

34. Definitions:

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

    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.

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

35. 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.]

36. Data Exclusion Procedures for SIP Compliance: Limited amounts of CEMS emissions data collected during startup, shutdown, and malfunction, and described in Condition 37 below, may be excluded from the corresponding SIP-based compliance demonstration, provided that best operational practices to minimize emissions are adhered to, the duration of data excluded is minimized, and the procedures for data exclusion listed below are followed. As provided by the authority in Rule 62-210.700(5), F.A.C., these conditions replace the provisions in Rule 62-210.700(1), F.A.C.

    a. *Limiting Data Exclusion.* If the compliance calculation using all the CEMS emission data indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

    b. *Event Driven Exclusion.* There must be an underlying event (startup, shutdown, or malfunction) in order to exclude data. If there is no underlying event, then no data may be excluded.

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

37. Allowable Data Exclusions: The following data may be excluded from the corresponding SIP-based compliance demonstration for each of the events listed below:

    a. *Steam Turbine/HRSG System Cold Startup:* Up to six hours (in any 24-hr period) of excess emissions from the combustion turbine/HRSG system due to cold startup of the steam turbine/HRSG system may be excluded. A "cold startup of the steam turbine/HRSG system" is defined as startup of the combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

{Permitting Note: During a cold startup of the steam turbine system, the gas turbine/HRSG system is brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue.}

b. *Steam Turbine/HRSG System Warm Startup:* Up to four hours (in any 24-hr period) of excess emissions from the combustion turbine/HRSG system due to warm startup of the steam turbine/HRSG system may be excluded. A "warm startup of the steam turbine/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine lasting at least 8 hours and less than 48 hours.

c. *Shutdown:* Up to three hours (in any 24-hr period) of excess emissions from the gas turbine/HRSG system due to shutdown of the combined cycle operation may be excluded.

d. *Malfunction*: Up to 2 hours (in any 24-hr period) of excess emissions from the combustion turbine/HRSG system due to a documented malfunction may be excluded. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic email.

All valid emissions data (including data collected during startup, shutdown, and malfunction) shall be used to report emissions for the Annual Operating Report.

[Rules 62-210.200(BACT), 62-210.370, and 62-210.700, F.A.C.]

38. Ammonia Injection: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer and as provided in Condition 13. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbine/HRSG system including the pollution control equipment.
[Design; Rules 62-210.200(BACT), 62-212.400(PSD), and 62-210.700, F.A.C.]

39. Notification Requirements: The owner or operator shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate non-compliance for a given averaging period. Within one working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data. [Rule 62-4.070, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

40. CEM Systems: Subject to the following, the permittee shall install, calibrate, operate, and maintain continuous emission monitoring systems (CEMS) to measure and record the emissions of CO, NO_X, and SO_2 from the combined cycle combustion turbine in terms of the applicable standards. Each monitoring system shall be installed, and functioning within the required performance specifications by the time of the initial compliance demonstration.

a. *CO Monitor:* The CO monitor shall be installed 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 RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

b. *NO_X Monitor:* A NO_X monitor installed to meet the requirements of 40 CFR 75, and that is continuing to meet the ongoing requirements of Part 75, may be used to meet the requirements of this permit and 40 CFR 60.49(c), Subpart Da, except that the owner or operator shall also meet the requirements of 60.51Da and the specific conditions of this permit. Data reported to meet the requirements of 60.51Da and the BACT limits of this permit shall not include data substituted using the missing data procedures in Subpart D of Part 75, nor shall the data have been bias adjusted according to Part 75.

c. *SO_2 Monitor:* The SO_2 monitor shall be installed pursuant to 40 CFR 60, Appendix B, Performance Specification 2. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The RATA tests required for the SO_2 monitor shall be performed using EPA Method 7 or 7E in Appendix A of 40 CFR 60. The SO_2 monitor span value shall be set according to 60.49Da(i). Alternatively, an SO2 monitor installed to meet the requirements of 40 CFR 75, and that is continuing to meet the ongoing requirements of Part 75, may be used to meet the requirements of this permit and 40 CFR 60.49(b), Subpart Da, except that the owner or operator shall also meet the requirements of 60.51Da and the specific conditions of this permit. Data reported to meet the requirements of 60.51Da and the BACT limits of this permit shall not include data substituted using the missing data procedures in Subpart D of Part 75, nor shall the data have been bias adjusted according to Part 75.

d. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be continuously monitored at the location where CO, NO_X, and SO_2 are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

[Rules 62-4.070(3), 62-210.200(BACT), F.A.C., and 40 CFR 60.49Da and Subpart 75]

41. Mercury Monitoring: Mercury emissions shall be monitored in accordance with 40 CFR 60.45Da and 60.49Da. [Rules 62-4.070(3), F.A.C., and 40 CFR 60.45Da and 60.49Da.]

42. Continuous Flow Monitor: A continuous flow monitor shall be installed to determine stack exhaust flow rate to be used in determining mass emission rates. The flow monitor shall be certified and operated according to the requirements of 40 CFR 75. As an alternative to the stack flow monitor, a fuel flow monitoring system certified and operated according to the requirements of appendix D of 40 CFR Part 75 may be installed. [Rules 62-4.070(3), 62-210.200(BACT), F.A.C., and 40 CFR 60.49Da and Subpart 75]

43. Wattmeter: A wattmeter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours must be installed, calibrated, maintained, and operated in accordance with the manufacturer's specifications. [40 CFR 60.49Da]

44. Moisture Correction: If necessary, the owner or operator shall install a system to determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). [Rules 62-4.070(3), 62-210.200(BACT), F.A.C]

45. 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 prior to the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with meeting the permitted NO_X limits for the combustion turbine load condition.
[Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

46. CEMS Data Requirements for BACT Standards:

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition Nos. 15 - 24 of this section. These requirements cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs. Additional reporting and monitoring may be required by the individual subparts.}

a. *Data Collection*: Except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions shall be monitored and recorded during all operation including startup, shutdown, and malfunction.

b. *Operating Hours and Operating Days*: An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit. [Rule 62-4.070, F.A.C.]

c. *Valid Hour*: 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. 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.

   1) Hours that are **not operating** hours are **not valid** hours.
   2) For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data and the 1-hour block average is not valid.
   3) During fuel switching an hour in which syngas is fired is attributed towards compliance with the permit standards for syngas firing.

d. *Rolling 24-Hour Average:* Compliance shall be determined after each valid hourly average is obtained by calculating the arithmetic average of that valid hourly average and the previous 23 valid hourly averages.

   {Permitting Note: There may be more than one 24-hour compliance demonstration required for CO emissions depending on the use of alternate methods of operation}

e. *Rolling 30-day Average*: Compliance shall be determined after each operating day by calculating the arithmetic average of all the valid hourly averages from that operating day and the prior 29 operating days.

f. *Rolling 12-month Total*: Compliance shall be determined after each calendar month by calculating the total emissions from that calendar month and the last 11 calendar months.

g. *Missing Data/Bias Adjustments:* If the owner or operator has installed a CEMS to meet the requirements of Part 75, data reported to show compliance with any SIP-based limit shall not include data substituted using the missing data procedures in Subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

h. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, and fuel switches. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 36 and 37 of this subsection.

i. *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]]

REPORTING AND RECORD KEEPING REQUIREMENTS

47. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, and fuel switching). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

48. 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 gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

49. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur content. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

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

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

51. CEMS Data Assessment Report: The Data Assessment Report required by 40 CFR, Appendix F shall be submitted to the Compliance Authority on a quarterly basis for each CEMS required for compliance with a BACT limit only. Separate reporting may be required for CEMS installed for purposes of compliance with an NSPS limit, or Acid Rain.

52. Excess Emissions Reporting:

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

b. *SIP Quarterly Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO, and SO_2 emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. A summary of data excluded from SIP compliance calculations should also be provided. In addition, the report shall summarize the CO, NO_X, SO_2, and Hg CEMS systems monitor availability for the previous quarter.

c. *NSPS Reporting*: Within 30 days following each calendar quarter, the permittee shall submit the written reports required under 40 CFR 60.51Da for the previous quarter or semi-annual period to the Compliance Authority. Also, within 30 days following the end of each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions, as applicable, and defined by NSPS Da, and/or NSPS KKKK that occurred during the previous semi-annual period to the Compliance Authority.

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, 60.51Da, and 60.4375]

53. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility in accordance with 62-210.370. Emissions reported for Unit B shall include estimates of emissions from the flare and startup stack. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

FEDERAL REQUIREMENTS

{Permitting Note: The following descriptions summarize specific regulations of the various subparts that are potentially applicable to Unit B. These summaries are based on the current status of each subpart and are included for purposes of clarification.}

54. NSPS Subpart Da: The provisions of Subpart Da apply to heat recovery steam generators and the associated stationary combustion turbine(s) burning fuels containing 75 percent by (heat input) or more synthesis-coal gas on a 12-month rolling average. If Unit B burns 75 percent or more syngas on a 12-month rolling average, the CT/HRSG system will be subject to and must comply with the requirements of Subpart Da and not KKKK. Applicable requirements of Subpart Da are summarized below, and details of the Subpart can be found in Appendix Da of this permit.

NSPS Subpart Da Requirements					
Applicable When Firing ≥ 75% Syngas (12-month rolling average)					
Pollutant	Method of Operation	Limit Lb/mmBtu	Limit Lb/MWh	Averaging Time	Method of Compliance
SO_2	All Modes	N/A	1.4	30-day Rolling	CEMS
NO_X	CT/CT & DB	N/A	1.0	30-day Rolling	CEMS
	DB	N/A	1.0	30-day Rolling	CEMS
PM	All Modes	0.015	0.14		CEMS[a]
		20% Opacity		6-minute block	Annual Test
Mercury	All Modes	N/A	0.000020	12-month Rolling	CEMS/Sorbent Trap

a. Demonstration of a fuel sulfur specification of ≤ 0.15 lb S/mmBtu fuel also demonstrates compliance with the PM limit for units that burn liquid or gaseous fuels.

[40 CFR 60 Subpart Da]

55. NSPS Subpart KKKK: The proposed provisions of Subpart KKKK apply to stationary gas turbines constructed after February 18, 2005. If Unit B burns less than 75 percent syngas on a 12-month rolling

average, the CT/HRSG system will be subject to and must comply with the requirements of Subpart KKKK, and not Subparts GG and Da. Applicable requirements of Subpart KKKK are summarized below, and details of the Subpart can be found in Appendix KKKK of this permit.

NSPS Subpart KKKK Requirements					
Applicable When Firing < 75% Syngas (12-month rolling average)					
Pollutant	Method of Operation	Limit		Averaging Time	Method of Compliance
		ppm @ 15% O_2	Or Lb/MWhr		
NO_X	CC	15	0.43	30-day Rolling	CEMS
	SC	15	0.43	4-hr Rolling	CEMS
SO_2	All modes	0.060 lb/mmBtu		Daily Sampling	Fuel Records
		Or 0.90 lb/MWh		Three 1-hr Runs	Annual Test

[40 CFR 60 Subpart KKKK]

56. NESHAP Subpart YYYY: The combustion turbine is subject to 40 CFR 63, Subpart A, Identification of General Provisions and 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. On August 18, 2004 EPA issued a final rule staying the effectiveness of this Subpart with respect to lean premix and diffusion flame gas-fired combustion turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 and comply with any other applicable requirement of Subpart YYYY upon final action by EPA and publication in the Federal Register. Subpart YYYY specifies an emission limit of 91 parts per billion (ppbv) of formaldehyde (CH_2O) applicable to stationary gas turbines.

[40 CFR 63 Subpart YYYY]

B. Unit B Flare (EU 031)

ID	Emission Unit Description
031	Unit B Flare – A multipoint flare (including 8 pilot flares) enclosed in a 20 foot thermal barrier fence used to combust syngas during startups (once the gasifier switches fuels from natural gas to coal), and during plant upset conditions.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOCs).
[Rule 62-210.200 (BACT), F.A.C.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one multipoint flare system, approximately 214 feet by 123 feet, enclosed in a 20 foot thermal barrier fence. The flare system will be designed to combust synthesis gas during startup, and during upsets of the gasification plant or the combustion turbine. The flare system will also include 8 pilot flares fueled by natural gas.
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

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

4. Authorized Fuels: Only natural gas containing no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas shall be fired in the pilot flares.

5. Methods of Operation: Subject to the restrictions and requirements of this permit, the flare may operate under the following methods of operation.

   a. *Pilot Flare*: The 8 pilot flares shall be operated with a flame present at all times.

   b. *Synthesis Gas Flaring:* Once the gasifiers reach a reducing atmosphere, synthesis gas shall be directed through the gas clean-up processes to the flare. Flaring will take place only until there is sufficient synthesis gas production to support operation of the combustion turbine. Operation of the combustion turbine may be accomplished by mixing the synthesis gas with natural gas.

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

6. Work Practice: Good combustion practices will be utilized at all times to ensure emissions from the flare system are minimized. The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of the flare and pilot systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions.
[Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

7. Pilot Flares: The 8 pilot flares shall be operated with a flame present at all times. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDS

8. Pilot Flare Records: The permittee shall keep readily accessible records demonstrating the presence of a flame on the pilot flares.

9. Fuel Records: The permittee shall keep records sufficient to determine the annual throughput of natural gas of this unit for use in the Annual Operating Report.
[Rule 62-204.800(7)(b)16, F.A.C]

C. Unit B Cooling Tower (EU 032)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
032	Unit B Cooling Tower – consisting of six cells with six individual exhaust fans.

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one 6-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 86,000 gpm; a design air flow rate of 1,361,880 acfm per cell; drift eliminators; and a drift rate of no more than 0.0005 percent of the circulating water flow. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing commercial operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-210.200(BACT), F.A.C.]

{Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on these design criteria, potential emissions are estimated to be less than 14 tons of PM per year and less than 6 tons of PM_{10} per year. Actual emissions are expected to be lower than these rates.}

D. Unit B Materials Storage and Handling (Units 33, 34, and 35)

This section of the permit addresses the following emissions unit.

<table>
<tr><th>ID</th><th colspan="2">Emission Unit Description</th></tr>
<tr><td rowspan="9">033</td><td colspan="2">Unit B Coal Mill and Coal Storage – including coal crushing, and crushed coal storage, coal pulverizing and feed preparation.</td></tr>
<tr><td>Point ID No.</td><td>Description</td></tr>
<tr><td>CMS1</td><td>Coal Mill Silo No. 1 Baghouse</td></tr>
<tr><td>CMS2</td><td>Coal Mill Silo No. 2 Baghouse</td></tr>
<tr><td>CMS3</td><td>Coal Mill Silo No. 3 Baghouse</td></tr>
<tr><td>CMS4</td><td>Coal Mill Silo No. 4 Baghouse</td></tr>
<tr><td>PCS1</td><td>Pulverized Coal Storage Bin No. 1 Baghouse</td></tr>
<tr><td>PCS2</td><td>Pulverized Coal Storage Bin No. 2 Baghouse</td></tr>
<tr><td>PCS3</td><td>Pulverized Coal Storage Bin No. 3 Baghouse</td></tr>
<tr><td></td><td>PCS4</td><td>Pulverized Coal Storage Bin No. 4 Baghouse</td></tr>
<tr><td>034</td><td colspan="2">Unit B Gasification Ash Storage – including fly ash storage silo and baghouse.</td></tr>
<tr><td>035</td><td colspan="2">Unit B Coal Handling – Including coal conveying and transfer.</td></tr>
</table>

APPLICABLE STANDARDS AND REGULATIONS

1. <u>BACT Determinations</u>: A determination of the Best Available Control Technology (BACT) was made for particulate matter (PM/PM_{10}). To satisfy the BACT requirements for this unit the visible emissions limits, and the baghouse specifications act as surrogate standards for particulate matter.
[Rule 62-210.200 (BACT), F.A.C.]

2. <u>NSPS Requirements</u>: These units are subject to 40 CFR 60, Subpart A (Identification of General Provisions) and 40 CFR 60, Subpart Y (Standards of Performance for Coal Preparation Plants). The Department determines that the BACT emissions performance requirements are as stringent as or more stringent than the limits imposed by the applicable NSPS provisions. Some separate reporting and monitoring may be required by the individual subparts.

EQUIPMENT AND CONTROL TECHNOLOGY

3. <u>Equipment Description</u>: The permittee is authorized to construct, operate, and maintain equipment needed for the grinding, storage, and handling of Unit B coal. Equipment will include a radial-pedestal stacker conveyor; a crusher shed with tramp screens, magnetic separator, sampling system, and crusher; four crushed coal silos with dedicated pulverizers; four surge bins; a high pressure coal feeder system; and all associated conveyor systems.

4. <u>Baghouse Controls</u>: Each coal mill silo and each pulverized coal storage bin will be controlled by a baghouse system. Each required baghouse shall be designed, operated, and maintained to achieve a PM design specification of 0.01 gr/dscf and a PM_{10} design specification of 0.0085 gr/dscf.
[Rules 62-4.070(3), and 62-210.200 (BACT), F.A.C.]

PERFORMANCE REQUIREMENTS

5. <u>Hours of Operation</u>: The hours of operation for this emissions unit are not limited (8760 hours per year).
[Rule 62-21.200 (PTE), F.A.C.]

6. Unconfined Emissions of Particulate Matter

   a. No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity without taking reasonable precautions to prevent such emissions. Such activities include, but are not limited to: vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling.

   b. Reasonable precautions shall include the following:

      (1) Landscaping and planting of vegetation.

      (2) Application of water to control fugitive dust from activities such as demolition of buildings, grading roads, construction, and land clearing.

      (3) Water supply lines, hoses and sprinklers shall be located near all stockpiles of raw materials, coal, and petroleum coke.

      (4) All plant operators shall be trained in basic environmental compliance and shall perform visual inspections of raw materials, coal and petroleum coke periodically and before handling. If the visual inspections indicate a lack of surface moisture, such materials shall be wetted with sprinklers. Wetting shall continue until the potential for unconfined particulate matter emissions are minimized.

      (5) Water spray shall be used to wet the materials and fuel if inherent moisture and moisture from wetting the storage piles are not sufficient to prevent unconfined particulate matter emissions.

      (6) As necessary, applications of asphalt, water, or dust suppressants to unpaved roads, yards, open stockpiles and similar activities.

      (7) Paving of access roadways, parking areas, manufacture area, and fuel storage yard.

      (8) Removal of dust from buildings, roads, and other paved areas under the control of the owner or operator of the facility to prevent particulate matter from becoming airborne.

      (9) A vacuum sweeper shall be used to remove dust from paved roads, parking, and other work areas.

      (10) Enclosure or covering of conveyor systems where practicably feasible.

      (11) All materials at the plant shall be stored under roof. Materials, other than quarried materials, shall be stored on compacted clay or concrete, or in enclosed vessels.

      (12) Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.

      (13) Confining abrasive blasting where possible.

   c. In determining what constitutes reasonable precautions for a particular source, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice.

EMISSIONS AND TESTING REQUIREMENTS

7. Visible Emissions Standards: Visible emissions from each baghouse, and visible emissions from all coal processing and conveying equipment, coal storage systems, or coal transfer and loading systems and not controlled by a baghouse, shall not exceed 5 % opacity.

8. Testing Requirements: Each emission point shall be tested to demonstrate initial compliance with the visible emissions standards. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup. Thereafter, compliance with the visible emission limits shall be demonstrated during each federal fiscal year (October 1st to September 30th). Compliance with the visible emission limits shall be determined by

conducting EPA Method 9 tests. Tests shall be conducted in accordance with the applicable requirements in Appendix C of this permit as well as the applicable NSPS provisions.
[Rule 62-297.310(7)(a), F.A.C., and 40 CFR 60.252]

9. Test Reports: For each test conducted, the permittee shall file a test report including the information specified in Rule 62-297.310(8), F.A.C. with the compliance authority no later than 45 days after the last run of each test is completed. [Rules 62-297.310(8), F.A.C.]

SECTION IV. APPENDICES

CONTENTS

NSPS SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

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

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

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

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

The Department establishes the following standards as the Best Available Control Technology for the integrated gasification combined cycle Unit B at the Curtis H. Stanton Energy Center.

BACT Determinations – Stanton Energy Center Unit B

Best Available Control Technology (BACT) – Rule 62-210.200, F.A.C.			
While Firing Natural Gas[a]			
Pollutant	Stack Test, 3-Run Average		CEMS Average
	ppmvd @ 15% O_2	lb/hr[e]	
CO (DB)[f]	27.2/4.1	138.0/20.8	24-hr rolling
CO (w/o DB)[f]	20.5/4.1	79.0/15.8	
VOC (DB)	6.5	19.0	N/A
VOC (w/o DB)	2.4	5.3	
SO_2[b]	2.0 gr S/100 SCF of gas		N/A
SAM[b]	2.0 gr S/100 SCF of gas		N/A
PM/PM_{10}[c]	2.0 gr S/100 SCF of gas		N/A
	10 % opacity, 6-minute block average		
Ammonia[d]	5.0	N/A	N/A
While Firing Synthesis Gas[a]			
CO (DB)	20.5	140.5	24-hr rolling
CO (w/o DB)	15.8	90.7	
VOC (DB)	4.6	17.9	N/A
VOC (w/o DB)	2.4	7.9	
SO_2[b]	2.7	35.5	30-day rolling
PM/PM_{10}	Compliance with SO_2/CO standards		N/A
	10 % opacity, 6-minute block average		
SAM[b]	Compliance with SO_2		N/A
Ammonia[d]	5.0	N/A	N/A

a. For purposes of meeting the BACT and preconstruction review avoidance limits of this subsection, an hour in which a synthesis gas/natural gas fuel mixture is fired, is subject to the BACT limit for natural gas when the mixture contains greater than 75% natural gas (by heat input), and subject to the BACT limit for synthesis gas when the mixture contains 75% or less natural gas (by heat input) for that hour. Any hour in which both synthesis gas and natural gas are combusted in the combustion turbine due to fuel switching, shall be subject to the limits for synthesis gas firing.

b. The fuel sulfur specifications, established in Condition 12 of Section III, subsection A, effectively limit the potential emissions of SO_2 and SAM from the combustion turbine while firing natural gas and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition 49 of Section III, Subsection A. BACT for SO_2 while firing synthesis gas has been determined as 2.7 ppmvd and 35.5 lb/hr. Compliance with the SO_2 limit effectively limits the potential emissions of SAM while firing synthesis gas.

c. The fuel sulfur specifications for natural gas and the SO_2 standard for syngas, combined with the efficient combustion design and operation of the combustion turbine represent BACT for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion.

d. The SCR system shall be designed and operated for an ammonia slip limit of no more than 5 ppmvd corrected to 15% O_2 based on the average of three test runs. Notwithstanding this provision, ammonia slip may exceed 5 ppmvd but may not exceed 10 ppmvd corrected to 15% O_2 when the SCR system is voluntarily operated to reduce NOx emissions below 10 ppmvd.

e. Mass emission rate standards and concentrations are based on 100 percent full load operation, an ambient temperature of 70° F, and using the HHV of the fuel. The mass emission rate may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

f. These emission standards for CO when firing natural gas shall be determined in accordance with Condition 16.a of this subsection.

{Permitting Note: The above emissions standards effectively limit annual potential emissions from the combustion turbine/HRSG system to: 615 tons/year of CO, 83 tons/year of VOC, 155 tons/year of SO_2, less than 24 tons/year of SAM, and less than 156 tons/year of PM/PM_{10}.}

NSPS SUBPART Da REQUIREMENTS FOR STEAM GENERATING UNITS

When burning 75 percent (by heat input) or more synthesis coal gas, on a 12-month rolling average, Unit B heat recovery steam generator and the associated stationary combustion turbine are subject to NSPS Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978).

{Permitting Note: Numbering of the original NSPS rules in the following conditions has been preserved for ease of reference. Paragraphs that are not applicable have been omitted for clarity and brevity. When used in 40 CFR 60, the term "Administrator" shall mean the Secretary or the Secretary's designee.}

§ 60.40Da Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) Heat recovery steam generators that are associated with stationary combustion turbines burning fuels other than 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. Heat recovery steam generators and the associated stationary combustion turbine(s) burning fuels containing 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average are subject to this part and are not subject to subpart KKKK of this part. This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the combined cycle gas turbine burn fuels other than synthetic-coal gas, only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart. (The combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

[44 FR 33613, June 11, 1979, as amended at 63 FR 49453, Sept. 16, 1998, Redesignated at 70 FR 51268, Aug. 30, 2005, as amended at 71 FR 9876, Feb. 27, 2006]

§ 60.42Da Standard for particulate matter.

(b) On and after the date the particulate matter performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(c) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification is commenced after February 28, 2005, except for modified affected facilities meeting the requirements of paragraph (d) of this section, any gases that contain particulate matter in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under §60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel.

[44 FR 33613, June 11, 1979, Redesignated at 70 FR 51268, Aug. 30, 2005, as amended at 71 FR 9877, Feb. 27, 2006]

§ 60.43Da Standard for sulfur dioxide.

(i) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except as provided for under paragraphs (j) or (k) of this section, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6663, Feb. 14, 1989; 54 FR 21344, May 17, 1989; 65 FR 61752, Oct. 17, 2000. Redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9877, Feb. 27, 2006]

§ 60.44Da Standard for nitrogen oxides.

(2) *NOx reduction requirement.*

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25
Liquid fuels	30
Solid fuels	65

(c) Except as provided under paragraph (d) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$E_n=[86\ w+130x+210\ y+260\ z+340\ v]/100$

where:

En is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);

w is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v is the percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(e) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except for an IGCC meeting the requirements of paragraph (f) of this section, any gases that contain nitrogen oxides (expressed as NO_2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under §60.48Da(k).

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 63 FR 49453, Sept. 16, 1998; 66 FR 18551, Apr. 10, 2001; 66 FR 42610, Aug. 14, 2001. Redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9878, Feb. 27, 2006]

§ 60.45Da Standard for mercury.

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction or reconstruction commenced after January 30, 2004, any gases which contain Hg emissions in excess of 20×10^{-6} lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average using the procedures in §60.50Da(g).

[70 FR 28653, May 18, 2005. Redesignated and amended at 70 FR 51268, Aug. 30, 2005]

§ 60.48Da Compliance provisions.

(a) Compliance with the particulate matter emission limitation under §60.42Da(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under §60.42Da(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under §60.44Da(a) constitutes compliance with the percent reduction requirements under §60.44Da(a)(2).

(c) The particulate matter emission standards under §60.42Da, the nitrogen oxides emission standards under §60.44Da, and the Hg emission standards under §60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(e) After the initial performance test required under §60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under §60.43Da and the nitrogen oxides emission limitations under §60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under §60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under §60.43Da and the nitrogen oxides emission limitation under §60.44Da is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

(1) Compliance with applicable 30-day rolling average SO2 and NOX emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO2 and NOX for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NOX only), or emergency conditions (SO2) only.

(2) Compliance with applicable SO2 percentage reduction requirements is determined based on the average inlet and outlet SO2 emission rates for the 30 successive boiler operating days.

(3) Compliance with applicable daily average particulate matter emission limitations is determined by calculating the arithmetic average of all hourly emission rates for particulate matter each boiler operating day, except for data obtained during startup, shutdown, and malfunction.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under §§60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.

(i) Compliance provisions for sources subject to §60.44Da(d)(1), (e)(1), or (f). The owner or operator of an affected facility subject to §60.44Da(d)(1) or (e)(1) shall calculate NOX emissions by multiplying the average hourly NOX output concentration, measured according to the provisions of §60.49Da(c), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and dividing by the average hourly gross energy output, measured according to the provisions of §60.49Da(k).

(k) Compliance provisions for duct burners subject to §60.44Da(d)(1) or (e)(1). To determine compliance with the emission limitation for NOX required by §60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NOX emission limitation in §60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of NOX shall be computed using Equation 1 of this section:

$E = [(Csg \times Qsg)-(Cte \times Qte)]/(Osg \times h)$ (Eq. 1)

Where:

E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output

Csg = average hourly concentration of NOX exiting the steam generating unit, ng/dscm (lb/dscf)

Cte = average hourly concentration of NOX in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)

Qsg = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

Qte = average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)

Osg = average hourly gross energy output from steam generating unit, J (Mwh)

h = average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner

(ii) Method 7E of appendix A of this part shall be used to determine the NOX concentrations (Csg and Cte). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates (Qsg and Qte) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable NOX emission limitation in §60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NOX emission limitation in §60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NOX shall be computed using Equation 2 of this section:

$E = (Csg \times Qsd) / Occ$ (Eq. 2)

Where:

E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output

Csg = average hourly concentration of NOX exiting the steam generating unit, ng/dscm (lb/dscf)

Qsg = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(ii) The continuous emissions monitoring system specified under §60.49Da for measuring NOX and oxygen shall be used to determine the average hourly NOX concentrations (Csg). The continuous flow monitoring system specified in §60.49Da(l) shall be used to determine the volumetric flow rate (Qsg) of the exhaust gas. The sampling site shall be located at the outlet from the steam generating unit. Data from a continuous flow monitoring system certified (or recertified) following procedures specified in 40 CFR 75.20, meeting the quality assurance and quality control requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used.

(iii) The continuous monitoring system specified under §60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (Occ), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in §60.49Da(l), determine the mass rate (lb/hr) of NOX emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of 40 CFR part 75. If this compliance option is selected, the emission rate (E) of NOX shall be computed using Equation 3 of this section:

$E = (ERsg \times Hcc) / Occ$ (Eq. 3)

Where:

E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output

ERsg = average hourly emission rate of NOX exiting the steam generating unit heat input calculated using appropriate F-factor as described in Method 19, ng/J (lb/million Btu)

Hcc = average hourly heat input rate of entire combined cycle unit, J/hr (million Btu/hr)

Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(l) Compliance provisions for sources subject to §60.45Da. The owner or operator of an affected facility subject to §60.45Da (new sources constructed or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of §60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of §60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in §60.49Da(k). Compliance with the applicable standard under §60.45a is determined on a 12-month rolling average basis.

(m) Compliance provisions for sources subject to §60.43Da(i)(1)(i) or (j)(1)(i). The owner or operator of an affected facility subject to §60.43Da(i)(1)(i) or (j)(1)(i) shall calculate SO2 emissions by multiplying the average hourly SO2 output concentration, measured according to the provisions of §60.49Da(b), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of §60.49Da(k).

(n) Compliance provisions for sources subject to §60.42Da(c)(1). The owner or operator of an affected facility subject to §60.42Da(c)(1) shall calculate particulate matter emissions by multiplying the average hourly particulate matter output concentration, measured according to the provisions of §60.49Da(t), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of §60.49Da(k). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) Compliance provisions for sources subject to §60.42Da(c)(2) or (d). Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) Conduct an initial performance test according to the requirements in §60.50Da to demonstrate compliance by the applicable date specified in §60.8(a) and, thereafter, conduct the performance test annually, and

(2) An owner or operator must use opacity monitoring equipment as an indicator of continuous particulate matter control device performance and demonstrate compliance with §60.42Da(b). In addition, baseline parameters shall be established as the highest hourly opacity average measured during the performance test. If any hourly average opacity measurement is more than 110 percent of the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test. The new baseline shall not exceed the opacity limit specified in §60.42Da(b), and

(3) An owner or operator using an ESP to comply with the applicable emission limits shall use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP. Baseline parameters shall be established as average rates measured during the performance test. If a 3-hour average voltage and secondary current average deviates more than 10 percent from the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test, and

(4) An owner or operator using a fabric filter to comply with the applicable emission limits shall install, calibrate, maintain, and continuously operate a bag leak detection system according to paragraphs (o)(4)(i) through (viii) of this section.

(i) Install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(ii) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA–454/R–98–015, September 1997.

(iii) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(iv) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(v) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(vi) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel. Corrective actions must be initiated within 1 hour of a bag leak detection system alarm. If the alarm is engaged for more than 5 percent of the total operating time on a 30-day rolling average, a performance test must be performed within 60 days to demonstrate compliance.

(vii) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(viii) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors, and

(5) An owner or operator of a modified affected source electing to meet the emission limitations in §60.42Da(d) shall determine the percent reduction in particulate matter by using the emission rate for particulate matter determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, certify, maintain, and operate a continuous emission monitoring system measuring particulate matter emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a continuous monitoring system measuring particulate matter. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each continuous emission monitor shall be installed, certified, operated, and maintained according to the requirements in §60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19, section 4.1.

(5) At a minimum, valid continuous monitoring system hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/h, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(7) All valid continuous monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (j)(5) of this section are not met.

(8) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 90 percent of all operating hours per 30-day rolling average.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 63 FR 49454, Sept. 16, 1998; 66 FR 18552, Apr. 10, 2001; 66 FR 31178, June 11, 2001. Redesignated and amended at 70 FR 28653, 28654, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9878, Feb. 27, 2006]

§ 60.49Da Emission monitoring.

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) For a facility that qualifies under the numerical limit provisions of §60.43Da(d), (i), (j), or (k) sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of this section.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51a shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph §60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under §60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 shall be used to determine the SO2 concentration at the same location as the SO2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 shall be used to determine the NOX concentration at the same location as the NOX monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O2 or CO2 concentration at the same location as the O2 or CO2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (lb/million Btu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7 shall be used to determine O2, SO2, and NOX concentrations, respectively.

(2) SO2 or NOX (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Gas	500
Liquid	500
Solid.	1,000
Combination	500 (x+y)+1,000z

where:

x is the fraction of total heat input derived from gaseous fossil fuel,

y is the fraction of total heat input derived from liquid fossil fuel, and

z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under paragraph (i) of this section, the conditions under §60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under §60.44Da(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under §60.42Da, §60.43Da, §60.44Da, or §60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B and procedure 1 of appendix F of this subpart, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23, may be used.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of 40 CFR part 75.

(o) The owner or operator of a duct burner, as described in §60.41Da, which is subject to the NOX standards of §60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a continuous emissions monitoring system to measure NOX emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in §60.45Da shall install and operate a continuous emissions monitoring system (CEMS) to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to §75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of §60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in §60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in §60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in §72.2 of this chapter) to monitor Hg concentration, according to the procedures described in §75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of §75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in §75.11(b) or §75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (e.g., calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing record keeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under §60.42Da(c)(1) shall install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected source demonstrating compliance with the input-based emission limitation under §60.42Da(c)(2) may install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section in lieu of the requirements in §60.48Da(o).

(u) An owner or operator of an affected source that meets the conditions in either paragraph (u)(1) or (2) of this section is exempted from the continuous opacity monitoring system requirements in paragraph (a) of this section and the monitoring requirements in §60.48Da(o).

(1) A continuous monitoring system for measuring particulate matter emissions is used to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under §60.42Da(a)(1) or §60.42Da(c)(2) and is installed, certified, operated, and maintained on the affected source according to the requirements of paragraph (v) of this section.

(2) The affected source burns only oil that contains no more than 0.15 weight percent sulfur or liquid or gaseous fuels that when combusted without sulfur dioxide emission control, have a sulfur dioxide emissions rate equal to or less than or equal to 65 ng/J (0.15 lb/MMBtu) heat input.

(v) The owner or operator of an affected facility using a continuous emission monitoring system measuring particulate matter emissions to meet requirements of this subpart shall install, certify, operate, and maintain the continuous monitoring system as specified in paragraphs (v)(1) through (v)(3).

(1) The owner or operator shall conduct a performance evaluation of the continuous monitoring system according to the applicable requirements of §60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each relative accuracy test run of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and conducting performance tests using the following test methods.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

(ii) For oxygen (or carbon dioxide), EPA Reference Method 3, 3A, or 3B, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 55 FR 18876, May 7, 1990; 63 FR 49454, Sept. 16, 1998; 65 FR 61752, Oct. 17, 2000; 66 FR 18553, Apr. 10, 2001. Redesignated and amended at 70 FR 28653, 28654, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9880, Feb. 27, 2006]

§ 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for SO2 and NOX. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.42Da as follows:

(1) The dry basis F factor (O2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particular matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ±14 °C (320 ±25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O2 concentration. The O2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O2 traverse points. If the grab sampling procedure is used, the O2 concentration for the run shall be the arithmetic mean of the sample O2 concentrations at all traverse points.

(3) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO2 standards in §60.43Da as follows:

(1) The percent of potential SO2 emissions (%Ps) to the atmosphere shall be computed using the following equation:

$$\%P_s=[(100-\%R_f)(100-\%R_g)]/100$$

where:

%Ps=percent of potential SO2 emissions, percent.

%Rf=percent reduction from fuel pretreatment, percent.

%Rg=percent reduction by SO2 control system, percent.

(2) The procedures in Method 19 may be used to determine percent reduction (%Rf) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.

(3) The procedures in Method 19 shall be used to determine the percent SO2 reduction (%Rg) of any SO2 control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO2 control device and the average SO2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring system in §60.49Da (b) and (d) shall be used to determine the concentrations of SO2 and CO2 or O2.

(d) The owner or operator shall determine compliance with the NOX standard in §60.44Da as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NOX.

(2) The continous monitoring system in §60.49Da (c) and (d) shall be used to determine the concentrations of NOX and CO2 or O2.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of §§2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The Fc factor (CO2) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of §60.48(d)(1). The CO2 shall be determined in the same manner as the O2 concentration.

(f) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

(g) For the purposes of determining compliance with the emission limits in §§60.45Da and 60.46Da, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus half of the equivalent electrical energy in the unit's process stream.

(1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (i.e., 250 million Btu/hr input to an electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit); 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 million Btu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).

(2) Use the Equation 1 of this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$ER_{cogen} = \frac{M}{\left(V_{grid} + 0.75 \times V_{process}\right)} \quad \text{(Eq. 1)}$$

Where:

ERcogen = Cogeneration Hg emission rate over a compliance period in lb/MWh;

E = Mass of Hg emitted from the stack over the same compliance period (lb);

Vgrid = Amount of energy sent to the grid over the same compliance period (MWh); and

Vprocess = Amount of energy converted to steam for process use over the same compliance period (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in §60.45Da according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in §60.8(a). The required continuous monitoring systems must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the continuous monitoring systems for 12 successive months of unit operation (excluding hours of unit startup, shutdown and malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or (h)(3) of this section, as applicable. If, for any month in the initial

performance test, the minimum data capture requirement in §60.49Da(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first such month, the substitute monthly Hg emission rate shall be the arithmetic average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in pounds (lb), using either Equation 2 in paragraph (h)(2)(i)(A) of this section or Equation 3 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 4 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 2 below to calculate the Hg mass emissions for each valid hour:

$$E_h = K\,C_h Q_h t_h \qquad \text{(Eq. 2)}$$

Where:

Eh = Hg mass emissions for the hour, (lb)

K = Units conversion constant, 6.24 × 10− 11 lb-scm/μg-scf

Ch = Hourly Hg concentration, wet basis, (μg/scm)

Qh = Hourly stack gas volumetric flow rate, (scfh)

th = Unit operating time, i.e., the fraction of the hour for which the unit operated. For example, th = 0.50 for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use Equation 3 below to calculate the Hg mass emissions for each valid hour:

$$E_h = K\,C_h Q_h t_h \left(1-B_{ws}\right) \qquad \text{(Eq. 3)}$$

Where:

Eh = Hg mass emissions for the hour, (lb)

K = Units conversion constant, 6.24 × 10− 11 lb-scm/μg-scf

Ch = Hourly Hg concentration, dry basis, (μg/dscm)

Qh = Hourly stack gas volumetric flow rate, (scfh)

th = Unit operating time, i.e., the fraction of the hour for which the unit operated

Bws = Stack gas moisture content, expressed as a decimal fraction (e.g., for 8 percent H2O, Bws = 0.08)

(C) Use Equation 4, below, to calculate M, the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 2 or 3 (as applicable):

$$M = \sum_{h=1}^{n} E_h \qquad \text{(Eq. 4)}$$

Where:

M = Total Hg mass emissions for the month, (lb)

Eh = Hg mass emissions for hour "h", from Equation 2 or 3 of this section, (lb)

n = The number of unit operating hours in the month with valid CEM and electrical output data, excluding hours of unit startup, shutdown and malfunction

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 5, below. For a cogeneration unit, use Equation 1 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \qquad \text{(Eq. 5)}$$

Where:

ER = Monthly Hg emission rate, (lb/MWh)

M = Total mass of Hg emissions for the month, from Equation 4, above, (lb)

P = Total electrical output for the month, for the hours used to calculate M. (MWh)

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 6 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=i}^{12} (ER)_i n_i}{\sum_{i=i}^{12} n_i} \quad \text{(Eq. 6)}$$

Where:

Eavg = Weighted 12-month rolling average Hg emission rate, (lb/MWh)

(ER)i = Monthly Hg emission rate, for month "i", (lb/MWh)

n = The number of unit operating hours in month "i" with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in §75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 3 through 5 of this section, except that for a particular pair of sorbent traps, Ch in Equation 3 shall be the flow-proportional average Hg concentration measured over the data collection period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride (Hg° or $HgCl2$) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using HgCl2 standards, as described in section 8.3 of Performance Specification 12–A in appendix B to this part (note: Hg° standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 65 FR 61752, Oct. 17, 2000. Redesignated and amended at 70 FR 28653, 28655, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9881, Feb. 27, 2006]

Editorial Note: At 70 FR 51269, Aug. 30, 2005, the Environmental Protection Agency published a document in the Federal Register, attempting to amend §60.50Da. However, because of inaccurate amendatory language, this amendment could not be incorporated. For the convenience of the user, the language at 70 FR 51269 is set forth as follows:

f. Revising the existing reference in paragraph (e)(2) from "§60.48a(d)(1)" to "§60.48Da(d)(1)";

§ 60.51Da Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, particulate matter, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NOX only), emergency conditions (SO2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of §60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (ni) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (so) and inlet emission rates (si) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (Eo*) and the upper confidence limit for the mean inlet emission rate (Ei*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (Eo*) and the allowable emission rate (Estd) as applicable.

(d) If any standards under §60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under §60.48Da(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the sulfur dioxide emission standard under §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of §60.50Da and Method 19 (appendix A); and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO2 and/or NOX and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

[44 FR 33613, June 11, 1979, as amended at 63 FR 49454, Sept. 16, 1998; 64 FR 7464, Feb. 12, 1999. Redesignated and amended at 70 FR 28653, 28656, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005]

§ 60.52Da Recordkeeping requirements.

The owner or operator of an affected facility subject to the emissions limitations in §60.45Da or §60.46Da shall provide notifications in accordance with §60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of §60.7(f).

[70 FR 28656, May 18, 2005. Redesignated and amended at 70 FR 51268, Aug. 30, 2005]

GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

NSPS SUBPART KKKK REQUIREMENTS FOR STATIONARY COMBUSTION TURBINES

When burning less than 75 percent (by heat input) synthesis coal gas, on a 12-month rolling average, Unit B heat recovery steam generator and the associated stationary combustion turbine are subject to NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines).

Introduction

§ 60.4300 What is the purpose of this subpart?

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

Applicability

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

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

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

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NOX) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NOX emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NOX) and sulfur dioxide (SO2).

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

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

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

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

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

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1) or (a)(2) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

General Compliance Requirements

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

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

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NOX emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Monitoring

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

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

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

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

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

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

(a) If you are not using water or steam injection to control NOX emissions, you must perform annual performance tests in accordance with §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 §§60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NOX formation characteristics, and you must monitor these parameters continuously.

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

(iii) For any turbine that uses SCR to reduce NOX emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NOX emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

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

If the option to use a NOX CEMS is chosen:

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

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

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

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

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

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

For purposes of identifying excess emissions:

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

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both 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 O2 concentration exceeds 19.0 percent O2 (or the hourly average CO2 concentration is less than 1.0 percent CO2), a diluent cap value of 19.0 percent O2 or 1.0 percent CO2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NOX concentrations to 15 percent O2 is not allowed.

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

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

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

(1) For simple-cycle operation:

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

Where:

E = hourly NOX emission rate, in lb/MWh, (NOX)h = hourly NOX emission rate, in lb/MMBtu,

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

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

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \quad \text{(Eq. 2)}$$

Where:

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

(Pe)t = electrical or mechanical energy output of the combustion turbine in MW,

(Pe)c = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad \text{(Eq. 3)}$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 106 = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_x)_m}{BL * AL} \quad \text{(Eq. 4)}$$

Where:

E = NOX emission rate in lb/MWh,

(NOX)m = NOX emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

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

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

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

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep onsite 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.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NOX emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping onsite (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustionfuel?

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

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

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for units located in continental areas and 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO2/J (0:42 lb SO2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Reporting

§ 60.4375 What reports must I submit?

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

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

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

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

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

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

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

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

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

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NOX emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4- hour rolling average NOX emission rate" is the arithmetic average of the average NOX emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NOX emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NOX emission rate is obtained for at least 3 of the 4 hours. 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, CO2 or O2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

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

(c) 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.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO2?

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

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

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

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

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

(a) If you operate an emergency combustion turbine, you are exempt from the 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.

§ 60.4395 When must I submit my reports?

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

Performance Tests

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

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

(1) 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. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NOX emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \quad \text{(Eq. 5)}$$

Where:

E = NOX emission rate, in lb/MWh

$1.194 \times 10{-7}$ = conversion constant, in lb/dscf-ppm

(NOX)c = average NOX concentration for the run, in ppm

Qstd = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

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

(2) Sampling traverse points for NOX and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multihole 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 CO2 (or O2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NOX concentration during the stratification test; or

(B) For turbines with a NOX standard greater than 15 ppm @ 15% O2, 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 to 15 ppm @ 15% O2, 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 ±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 CO2 (or O2) 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.

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

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

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

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

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

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

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

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

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

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

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

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NOX emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

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

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

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

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

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

(2) Measure the SO2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad \text{(Eq. 6)}$$

Where:

E = SO2 emission rate, in lb/MWh

1.664 × 10−7 = conversion constant, in lb/dscf-ppm

(SO2)c = average SO2 concentration for the run, in ppm

Qstd = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(3) Measure the SO2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO2 emission rate in lb/MWh.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

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

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

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 §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

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

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation. *ISO conditions* means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

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

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

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

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

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

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

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

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

Table 1_to Subpart KKKK of Part 60_Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NOX emission standard
New turbine firing natural gas, electric generating	[le] 50 MMBtu/h...	42 ppm at 15. percent O2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive.	[le] 50 MMBtu/h...	100 ppm at 15 percent O2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas.	> 50 MMBtu/h and [le] 850 MMBtu/h	25 ppm at 15 percent O2 or 150 ng/J of useful output (1.2 lb/ MWh).
New, modified, or reconstructed turbine firing natural gas.	> 850 MMBtu/h...	15 ppm at 15 percent O2 or 54 ng/J of useful output (0.43 lb/ MWh)
New turbine firing fuels other than natural gas, electric generating	[le] 50 MMBtu/h...	96 ppm at 15 percent O2 or 700 . ng/J of useful output (5.5 lb/ MWh).
New turbine firing fuels other than natural gas, mechanical drive.	[le] 50 MMBtu/h...	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and [le] 850 MMBtu/h	74 ppm at 15 percent O2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas.	> 850 MMBtu/h...	42 ppm at 15 percent O2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine.	[le] 50 MMBtu/h...	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas.	> 50 MMBtu/h and [le] 850 MMBtu/h.	42 ppm at 15 percent O2 or 250 ng/J of useful output (2.0 lb/ MWh).
Modified or reconstructed turbine firing fuels other than natural gas.	> 50 MMBtu/h and [le] 850 MMBtu/h	96 ppm at 15 percent O2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F.	[le] 30 MW output.	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0°F.	> 30 MW output.	96 ppm at 15 percent O2 or 590 ng/J of useful 75 output (4.7 lb/ MWh).
Heat recovery units operating independent of the combustion turbine.	All sizes.........	54 ppm at 15 percent O2 or 110 ng/J of useful output (0.86 lb/MWh).

STANDARD CONDITIONS

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

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

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

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

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

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

    a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

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

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

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

14. Determination of Process Variables

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

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

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

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

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

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

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

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

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

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

RECORDS AND REPORTS

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

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

SECTION IV. APPENDIX Y

NSPS SUBPART Y REQUIREMENTS FOR COAL PREPARATION PLANTS

The specific conditions of this subsection apply to the following emissions units.

ID	Emission Unit Description
033	Unit B Coal Mill and Coal Storage – including coal crushing, and crushed coal storage, coal pulverizing and feed preparation.
034	Unit B Gasification Ash Storage – including fly ash storage silo and baghouse.
035	Unit B Coal Handling – Including coal conveying and transfer.

1. NSPS Subpart A: The affected emissions units are also subject to the applicable General Provisions in Subpart A of 40 CFR 60, as adopted by Rule 62-204.800(8), F.A.C. [40 CFR 60, Subpart A]
2. NSPS Subpart Y: The affected emissions units are also subject to the applicable requirements for Coal Preparation Plants specified in NSPS Subpart Y of 40 CFR 60, as adopted by Rule 62-204.800(8), F.A.C. [40 CFR 60, Subpart Y]

{Permitting Note: Numbering of the original NSPS rules in the following conditions has been preserved for ease of reference with the rules. Paragraphs that are not applicable have been omitted for clarity and brevity. When used in 40 CFR 60, the term "Administrator" shall mean the Secretary or the Secretary's designee.}

§ 60.250 Applicability and Designation of Affected Facility.

(a) The provisions of this subpart are applicable to any of the following affected facilities in coal preparation plants which process more than 200 tons per day: thermal dryers, pneumatic coal cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems.

§ 60.251 Definitions.

(a) *Coal preparation plant* means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(b) Bituminous coal means solid fossil fuel classified as bituminous coal by ASTM Designation D388-77, 90, 91, 95, or 98a (incorporated by reference; see § 60.17).

(c) Coal means all solid fossil fuels classified as anthracite, bituminous, sub bituminous, or lignite by ASTM Designation D388-77, 90, 91, 95, or 98a (incorporated by reference; see § 60.17).

(d) Cyclonic flow means a spiraling movement of exhaust gases within a duct or stack.

(e) Thermal dryer means any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(f) Pneumatic coal-cleaning equipment means any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(g) Coal processing and conveying equipment means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts.

(h) Coal storage system means any facility used to store coal except for open storage piles.

(i) Transfer and loading system means any facility used to transfer and load coal for shipment.

§ 60.252 Standards for Particulate Matter.

(a) On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, an owner or operator shall not cause to be discharged into the atmosphere from any thermal dryer gases which:

(1) Contain particulate matter in excess of 0.070 g/dscm (0.031 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(c) On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, an owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment or coal storage system, gases which exhibit 20 percent opacity or greater. [40 CFR 60.252(a) and (c)].

60.253 Monitoring of operations.

(a) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±1.7 °C (±3 °F).

(2) For affected facilities that use venturi scrubber emission control equipment:

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(ii) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations.

(b) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under §60.13(b).

[41 FR 2234, Jan. 15, 1976, as amended at 54 FR 6671, Feb. 14, 1989; 65 FR 61757, Oct. 17, 2000]

§ 60.254 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the particular matter standards in §60.252 as follows:

(1) Method 5 shall be used to determine the particulate matter concentration. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin.

(2) Method 9 and the procedures in §60.11 shall be used to determine opacity.

[54 FR 6671, Feb. 14, 1989]

NESHAP SUBPART YYYY HAP STANDARDS FOR STATIONARY COMBUSTION TURBINES

The Unit B combustion turbine is subject to 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines

{Permitting Note: Numbering of the original NESHAP rules in the following conditions has been preserved for ease of reference. Paragraphs that are not applicable have been omitted for clarity and brevity.}

§ 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) 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, although it may be mounted on a vehicle for portability or transportability. Stationary combustion turbines covered by this subpart include simple cycle stationary combustion turbines, regenerative/recuperative cycle stationary combustion turbines, cogeneration cycle stationary combustion turbines, and combined cycle stationary combustion turbines. Stationary combustion turbines subject to this subpart 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.

(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.

§ 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.

§ 63.6095 When do I have to comply with this subpart?

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

(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 §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.

[69 FR 10537, Mar. 5, 2004, as amended at 69 FR 51188, Aug. 18, 2004]

Emission and Operating Limitations

§ 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.

General Compliance Requirements

§ 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.

Testing and Initial Compliance Requirements

§ 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 §63.6095 and according to the provisions in §63.7(a)(2).

§ 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.

§ 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 §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.

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

(a) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you use an oxidation catalyst emission control device, you must monitor on a continuous basis your catalyst inlet temperature in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.

(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.

(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.

§ 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 §63.6145(f).

Continuous Compliance Requirements

§ 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.

§ 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 §63.6150.

(c) Consistent with §§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 accordance with §63.6(e)(1)(i).

[69 FR 10537, Mar. 5, 2004, as amended at 71 FR 20467, Apr. 20, 2006]

Notifications, Reports, and Records

§ 63.6145 What notifications must I submit and when?

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

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

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

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

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

§ 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 §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 §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 §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) If you are operating as a stationary combustion turbine which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis, 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 (c)(1) through (c)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also 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 total fuel consumption on an annual basis.

(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.

(d) Dates of submittal for the annual report are provided in (d)(1) through (d)(5) of this section.

(1) The first annual report must cover the period beginning on the compliance date specified in §63.6095 and ending on December 31.

(2) The first annual report must be postmarked or delivered no later than January 31.

(3) Each subsequent annual report must cover the annual reporting period from January 1 through December 31.

(4) Each subsequent annual report must be postmarked or delivered no later than January 31.

(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 (d)(1) through (4) of this section.

(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.

§ 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 §63.10(b)(2)(xiv).

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

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

(5) Records of all maintenance on the air pollution control equipment as required in §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.

§ 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 §63.10(b)(1).

(b) As specified in §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.

Table 1 to Subpart YYYY of Part 63—Emission 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,	limit the concentration of formaldehyde to 91 ppbvd or less at 15 percent O2.
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	

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.

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 annual basis AND.	Test Method 320 of 40 CFR part 63, appendix A; ASTM D6348-03 provided an 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 O2 concentration at the sampling port location AND...	Method 3A or 3B of 40 CFR part 60, appendix A.	measurements to determine O2 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	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.

formaldehyde concentration to a
dry basis.

Table 5 to 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.

Table 6 to 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 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