



# Florida Department of Environmental Protection

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

Rick Scott  
Governor

Jennifer Carroll  
Lt. Governor

Herschel T. Vinyard Jr.  
Secretary

*Electronic Mail – Received Receipt Requested.*

Mr. James Miller, Plant Manager  
Lake Cogeneration, Ltd.  
39001 Golden Gem Drive  
Umatilla, Florida 32784

Re: Permit Nos. 0694801-015-AV and 0694801-014-AC (PSD-FL-176D)  
Lake Cogeneration Facility  
Updated Air Construction Permit and Renewed Title V Air Operation Permit

Dear Mr. Miller:

Enclosed are the permit packages for an air construction permit and a renewed Title V air operation permit for the Lake Cogeneration Facility. This existing facility is located in Lake County, at 39001 Golden Gem Drive, Umatilla, Florida 32784. The permit package includes the following documents:

- The draft air construction permit and supporting technical evaluation and preliminary determination document.
- The statement of basis, which summarizes the facility, the equipment and the primary rule applicability for the renewed Title V air operation permit.
- The draft/proposed renewed Title V air operation permit, which includes the specific permit conditions that regulates the emissions units covered by the proposed project.
- The Written Notice of Intent to Issue Air Permits provides important information regarding: the Permitting Authority's intent to issue air permits for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue air permits; the procedures for submitting comments on the draft/proposed permits; the process for filing a petition for an administrative hearing; and the availability of mediation.
- The Public Notice of Intent to Issue Permits is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The Public Notice of Intent to Issue Permits must be published as soon as possible and the proof of publication must be provided to the Department within seven days of the date of publication. Because this permit is being processed as a combined draft/proposed permit in order to reduce processing time, a duplicate copy of the proof of publication must also be transmitted by electronic mail within seven days of the date of publication to Ms. Ana Oquendo at EPA Region 4 at the following address: [oquendo.ana@epa.gov](mailto:oquendo.ana@epa.gov).

If you have any questions, please contact the Project Engineer, Tammy McWade, by telephone at (850) 717-9086 or by email at [tammy.mcwade@dep.state.fl.us](mailto:tammy.mcwade@dep.state.fl.us)

Sincerely,

Jeffery F. Koerner, Program Administrator  
Office of Permitting and Compliance  
Division of Air Resource Management

11-7-11  
(Date)

Enclosures  
JFK/aal/ttm

## WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMITS

---

*In the Matter of an*

*Application for an Air Construction Permit Modification and a Renewed Title V Air Operation Permit by:*

Lake Cogeneration, Ltd.  
39001 Golden Gem Drive  
Umatilla, FL 32784

*Responsible Official:*

Mr. James Miller, Plant Manager

Facility ID No. 0694801  
Permit Nos. 0694801-015-AV and  
0694801-014-AC (PSD-FL-176D)  
Lake Cogeneration Facility  
Air Construction Permit  
Renewed Title V Air Operation Permit  
Lake County, Florida

**Facility Location:** The applicant operates the existing Lake Cogeneration Facility, which is located in Lake County at 39001 Golden Gem Drive, Umatilla, Florida.

**Project:** The applicant applied on February 1, 2011, to the Department for an updated air construction permit and a renewed Title V air operation permit. Details of the project are provided in the application and the enclosed Technical Evaluation and Preliminary Determination.

The purpose of this project is to modify the original Air Construction Permit No. AC35-196459 (PSD-FL-176), and subsequent modifications thereto, applicable to Combined Cycle Units 1 and 2 for the following items: correct the nominal electrical production rate of each combustion turbine-electric generator from 52 megawatt (MW) to 50 MW; revise to include a performance curve identifying maximum heat input rate based on the fluctuating compressor inlet temperature; correct and update the allowable emission limits; remove the distinction between the normal operating mode and the SPRINT mode; include authorization to replace limited components for maintenance and repairs of the combined cycle combustion turbine system; change the annual test schedule from July 15<sup>th</sup> to within the federal fiscal year; and update the permit to be more consistent with recent air construction permits for combined cycle combustion turbines.

The renewed Title V air operation permit will include the applicable requirements of the updated draft air construction permit as well as other applicable regulatory requirements.

**Permitting Authority:** Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210 and 62-212, Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air construction permit is required to perform the proposed work. Applications for Title V air operation permits are subject to review in accordance with the provisions of Chapter 403, F.S. and Chapters 62-4, 62-210, and 62-213 of the F.A.C. The proposed project is not exempt from air permitting requirements and a Title V air operation permit is required to operate the facility.

The Division of Air Resource Management is the Permitting Authority responsible for making the permit determination for these projects. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/717-9000.

**Project File:** A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at the address indicated above for the Permitting Authority. The complete project file includes the draft air construction permit, the draft/proposed Title V air operation permit, the Statement of Basis, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may view the draft/proposed permits by visiting the following website:

<http://www.dep.state.fl.us/air/emission/apds/default.asp> and entering the permit numbers shown above.

Interested persons may contact the Permitting Authority's project review engineer for additional information at

## WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMITS

---

the address or phone number listed above.

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

The Permitting Authority gives notice of its intent to issue a Title V air operation permit to the applicant for the project described above. The applicant has provided reasonable assurance that continued operation of existing equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a final Title V air operation permit in accordance with the conditions of the draft/proposed Title V air operation permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

**Comments:** The Permitting Authority will accept written comments concerning the draft air construction permit or the draft/proposed Title V air operation permit for a period of 30 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 30-day period at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on these permitting actions. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly (FAW).

If a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If written comments received result in a significant change to the draft air construction permit or the draft/proposed Title V air operation permit, the Permitting Authority shall revise the draft air construction permit or the draft/proposed Title V air operation permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection. For additional information, contact the Permitting Authority at the above address or phone number.

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

## WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMITS

---

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

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

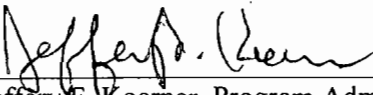
**Mediation:** Mediation is not available for this proceeding.

**EPA Review:** EPA has agreed to treat the draft/proposed Title V air operation permit as a proposed Title V air operation permit and to perform its 45-day review provided by the law and regulations concurrently with the public comment period, provided that the applicant also transmits an electronic copy of the required proof of publication directly to EPA at the following email address: [oguendo.ana@epa.gov](mailto:oguendo.ana@epa.gov). Although EPA's 45-day review period will be performed concurrently with the public comment period, the deadline for submitting a citizen petition to object to the EPA Administrator will be determined as if EPA's 45-day review period is performed after the public comment period has ended. The final Title V air operation permit will be issued after the conclusion of the 45-day EPA review period so long as no adverse comments are received that result in a different decision or significant change of terms or conditions. The status regarding EPA's 45-day review of this project and the deadline for submitting a citizen petition can be found at the following website address: <http://www.epa.gov/region4/air/permits/Florida.htm>.

**Objections:** Finally, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 days of the expiration of the Administrator's 45-day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to the issuance of any Title V air operation permit. Any petition shall be based only on objections to the permit that were raised with reasonable specificity during the 30-day public comment period provided in the Public Notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460. For more information regarding EPA review and objections, visit EPA's Region 4 web site at <http://www.epa.gov/region4/air/permits/Florida.htm>.

**WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMITS**

Executed in Tallahassee, Florida.

  
Jeffery F. Koerner, Program Administrator  
Office of Permitting and Compliance  
Division of Air Resource Management

11-7-11  
(Date)

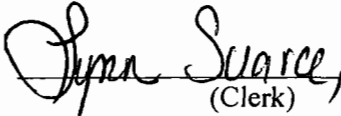
**CERTIFICATE OF SERVICE**

The undersigned duly designated deputy agency clerk hereby certifies that either this Written Notice of Intent to Issue an Air Construction Permit and a Renewed Title V Air Operation Permit (including the Public Notice, the Statement of Basis, the Draft/Proposed Permits and Technical Evaluation and Preliminary Determination), or a link to these documents available electronically on a publicly accessible server, was sent by electronic mail with received receipt requested before the close of business on 11-7-11 to the persons listed below.

Mr. James Miller, Lake Cogeneration Facility: ([jmiller@caithnessenergy.com](mailto:jmiller@caithnessenergy.com))  
Mr. Thomas Grace, Caithness Energy: ([tgrace@caithnessenergy.com](mailto:tgrace@caithnessenergy.com))  
Mr. Scott Osbourn, Golder Associates: ([sosbourn@golder.com](mailto:sosbourn@golder.com))  
Ms. Caroline Shine, DEP CD Office: ([caroline.shine@dep.state.fl.us](mailto:caroline.shine@dep.state.fl.us))  
Ms. Ana Oquendo, US EPA Region 4: ([oquendo.ana@epa.gov](mailto:oquendo.ana@epa.gov))  
Ms. Heather Ceron, US EPA Region 4: ([ceron.heather@epa.gov](mailto:ceron.heather@epa.gov))  
Ms. Katy Forney, EPA Region 4: ([forney.kathleen@epa.gov](mailto:forney.kathleen@epa.gov))  
Ms. Barbara Friday, DEP OPC: ([barbara.friday@dep.state.fl.us](mailto:barbara.friday@dep.state.fl.us))  
Ms. Lynn Searce, DEP OPC: ([lynn.searce@dep.state.fl.us](mailto:lynn.searce@dep.state.fl.us))

Clerk Stamp

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

 November 7, 2011  
(Clerk) (Date)

## Memorandum

## Florida Department of Environmental Protection

---

TO: Jeffery Koerner, Program Administrator, Office of Permitting and Compliance (OPC)  
THROUGH: Al Linero, P.E., Chemicals and Combustion Key Industry Group *aa*  
FROM: Tammy McWade, Chemicals and Combustion Key Industry Group *me*  
DATE: November 7, 2011  
SUBJECT: Project No. 0694801-014-AC (PSD-FL-176D), Draft Air Construction Permit  
Project No. 0694801-015-AV, Draft/Proposed Title V Air Permit Renewal  
Lake Cogeneration, Ltd.

Attached for your review is a concurrent Draft air construction and Draft/Proposed Title V air operation permit renewal package for the Lake Cogeneration Facility in Lake County at 39001 Golden Gem Drive in Umatilla, Florida. Briefly, the draft air construction permit replaces (updates) all previous construction permit for the facility, while the Draft/Proposed Title V air operation permit renewal incorporates the updated air construction permit and provides an early renewal to 12/31/2016.

The attached Technical Evaluation and Preliminary Determination and Statement of Basis provide a detailed description of the projects and the rationale for permit issuance. The present AC project is not considered a NSR Reform project, but the permits include annual reporting conditions for CO and NO<sub>x</sub> from previous NSR Reform projects.

Day 90 of the permitting time clock is November 24, 2011. There is no ongoing/open enforcement case for this facility, according to the Central District office.

I recommend your approval of the attached draft/proposed permit.

Attachments

## P.E. CERTIFICATION STATEMENT

### PERMITTEE

Lake Cogeneration, Ltd.  
39001 Golden Gem Drive  
Umatilla, Florida 32784

Facility ID No. 0694801  
Permit No. 0694801-015-AV  
Lake Cogeneration Facility  
Project No. 0694801-014-AC (PSD-FL-176D)  
Draft Air Construction Permit  
Project No. 0694801-015-AV  
Draft/Proposed Title V Air Permit Renewal  
Lake County, Florida

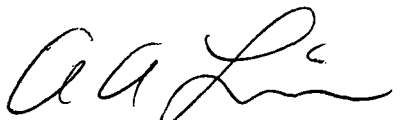
### PROJECT DESCRIPTION

The applicant applied on February 1, 2011, to the Department for an updated air construction permit and a renewed Title V air operation permit. The purpose of this project is to modify the original Air Construction Permit No. AC35-196459 (PSD-FL-176), and subsequent modifications thereto, applicable to Combined Cycle Units 1 and 2 for the following items: correct the nominal electrical production rate of each combustion turbine-electric generator from 52 MW to 50 MW; revise to include a performance curve identifying maximum heat input rate based on the fluctuating compressor inlet temperature; correct and update the allowable emission limits; remove the distinction between the normal operating mode and the SPRINT mode; include authorization to replace limited components for maintenance and repairs of the combined cycle combustion turbine system; change the annual test schedule from July 15<sup>th</sup> to within the federal fiscal year; and update the permit to be more consistent with recent air construction permits for combined cycle combustion turbines.

These changes are not expected to result in an actual emissions increase; therefore, the project is not subject to preconstruction review for the Prevention of Significant Deterioration (PSD) of Air Quality pursuant to Rule 62-212.400, Florida Administrative Code (F.A.C.).

The updated air construction permit No. 0694801-014-AC (PSD-FL-176D) will replace and supersede the previous air construction permit No. AC35-196459 (PSD-FL-176) and modifications thereto. The requirements of the original best available control technology (BACT) determination issued on November 20, 1991 pursuant to the rules for the PSD will be maintained and re-established therein. The requirements of Title 40 Code of Federal Regulations Part 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines applicable to units that commenced construction, modification or reconstruction after February 18, 2005 also apply.

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



A. A. Linero, P.E.

Registration Number: 26032

11/4/2011  
Date

## Scearce, Lynn

---

**From:** Scearce, Lynn  
**Sent:** Monday, November 07, 2011 3:27 PM  
**To:** 'jmillar@caithnessenergy.com'  
**Cc:** 'tgrace@caithnessenergy.com'; 'sosbourn@golder.com'; Shine, Caroline; 'oquendo.ana@epa.gov'; 'Ceron.Heather@epa.gov'; 'forney.kathleen@epa.gov'; McWade, Tammy; Linero, Alvaro; Friday, Barbara; Scearce, Lynn  
**Subject:** 0694801-014-AC-PSD-FL-176D, Notice of Draft / 0694801-015-AV, Notice of Draft/Proposed, Lake Cogeneration  
**Attachments:** 0694801-014-AC, and 015-AV, Lake Cogeneration signature page.pdf

Tracking:	Recipient	Delivery	Read
	'jmillar@caithnessenergy.com'		
	'tgrace@caithnessenergy.com'		
	'sosbourn@golder.com'		
	Shine, Caroline	Delivered: 11/7/2011 3:27 PM	
	'oquendo.ana@epa.gov'		
	'Ceron.Heather@epa.gov'		
	'forney.kathleen@epa.gov'		
	McWade, Tammy	Delivered: 11/7/2011 3:27 PM	
	Linero, Alvaro	Delivered: 11/7/2011 3:27 PM	Read: 11/7/2011 3:34 PM
	Friday, Barbara	Delivered: 11/7/2011 3:27 PM	
	Scearce, Lynn	Delivered: 11/7/2011 3:27 PM	Read: 11/7/2011 3:28 PM

Dear Mr. Miller:

Attached is the official **Notice of Draft AC and Notice of Draft/Proposed AV** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

**Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).**

Owner/Company Name: LAKE COGEN LTD.  
Facility Name: LAKE COGEN  
Project Number: 0694801-014-AC /0694801-015-AV  
Permit Status: DRAFT AND DRAFT/PROPOSED  
Permit Activity: CONSTRUCTION  
Facility County: LAKE

Click on the following link to access the permit project documents:

[http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf\\_permit\\_zip\\_files/0694801.014.AC.D\\_pdf.zip](http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0694801.014.AC.D_pdf.zip) and

[http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf\\_permit\\_zip\\_files/0694801.015.AV.D\\_PDF.zip](http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0694801.015.AV.D_PDF.zip)

The Office of Permitting and Compliance is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above,



or search for other project documents using the "*Air Permit Documents Search*" website at <http://www.dep.state.fl.us/air/emission/apds/default.asp>.

Permit project documents addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Office of Permitting and Compliance.

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

Regards,

**Lynn Searce**

Office of Permitting and Compliance (OPC)

Division of Air Resources Management

850-717-9025

## Scearce, Lynn

---

**From:** Thomas Grace [tgrace@caithnessenergy.com]  
**Sent:** Tuesday, November 08, 2011 9:06 AM  
**To:** Scearce, Lynn  
**Subject:** RE: 0694801-014-AC-PSD-FL-176D, Notice of Draft / 0694801-015-AV, Notice of Draft/Proposed, Lake Cogeneration

Thanks Lynn.

Tom Grace

---

**From:** Scearce, Lynn [mailto:Lynn.Scearce@dep.state.fl.us]  
**Sent:** 2011-11-07 15:27  
**To:** James Miller  
**Cc:** Thomas Grace; sosbourn@golder.com; Shine, Caroline; oquendo.ana@epa.gov; Ceron.Heather@epa.gov; forney.kathleen@epa.gov; McWade, Tammy; Linero, Alvaro; Friday, Barbara; Scearce, Lynn  
**Subject:** 0694801-014-AC-PSD-FL-176D, Notice of Draft / 0694801-015-AV, Notice of Draft/Proposed, Lake Cogeneration

Dear Mr. Miller:

Attached is the official **Notice of Draft AC and Notice of Draft/Proposed AV** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

*Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).*

Owner/Company Name: LAKE COGEN LTD.  
Facility Name: LAKE COGEN  
Project Number: 0694801-014-AC /0694801-015-AV  
Permit Status: DRAFT AND DRAFT/PROPOSED  
Permit Activity: CONSTRUCTION  
Facility County: LAKE

Click on the following link to access the permit project documents:  
[http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf\\_permit\\_zip\\_files/0694801.014.AC.D\\_pdf.zip](http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0694801.014.AC.D_pdf.zip) and  
[http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf\\_permit\\_zip\\_files/0694801.015.AV.D\\_PDF.zip](http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0694801.015.AV.D_PDF.zip)

The Office of Permitting and Compliance is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or

search for other project documents using the “*Air Permit Documents Search*” website at <http://www.dep.state.fl.us/air/emission/apds/default.asp>.

Permit project documents addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Office of Permitting and Compliance.

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

Regards,

**Lynn Searce**

Office of Permitting and Compliance (OPC)

Division of Air Resources Management

850-717-9025

*Please take a few minutes to share your comments on the service you received from the department by clicking on this link. [DEP Customer Survey](#).*

## **Scearce, Lynn**

---

**From:** Scearce, Lynn  
**Sent:** Monday, November 07, 2011 4:51 PM  
**To:** Scearce, Lynn; jmill@caithnessenergy.com  
**Cc:** tgrace@caithnessenergy.com; sosbourn@golder.com; Shine, Caroline; oquendo.ana@epa.gov; Ceron.Heather@epa.gov; forney.kathleen@epa.gov; McWade, Tammy; Linero, Alvaro; Friday, Barbara  
**Subject:** RE: 0694801-014-AC-PSD-FL-176D, Notice of Draft / 0694801-015-AV, Notice of Draft/Proposed, Lake Cogeneration

There is a revised link for the Draft/Proposed for 0694801-015-AV at [http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf\\_permit\\_zip\\_files/0694801.015.AV.P\\_pdf.zip](http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0694801.015.AV.P_pdf.zip). The AC link is still the same.

*Lynn Scearce*  
*Office of Permitting and Compliance (OPC)*  
*Division of Air Resource Management – DEP*  
*2600 Blair Stone Road, Mail Stop 5505*  
*Phone: 850-717-9025*

*Please take a few minutes to share your comments on the service you received from the department by clicking on this link. [DEP Customer Survey](#).*

**From:** Scearce, Lynn  
**Sent:** Monday, November 07, 2011 3:27 PM  
**To:** 'jmill@caithnessenergy.com'  
**Cc:** 'tgrace@caithnessenergy.com'; 'sosbourn@golder.com'; Shine, Caroline; 'oquendo.ana@epa.gov'; 'Ceron.Heather@epa.gov'; 'forney.kathleen@epa.gov'; McWade, Tammy; Linero, Alvaro; Friday, Barbara; Scearce, Lynn  
**Subject:** 0694801-014-AC-PSD-FL-176D, Notice of Draft / 0694801-015-AV, Notice of Draft/Proposed, Lake Cogeneration

Dear Mr. Miller:

Attached is the official **Notice of Draft AC and Notice of Draft/Proposed AV** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

*Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).*

Owner/Company Name: LAKE COGEN LTD.  
Facility Name: LAKE COGEN  
Project Number: 0694801-014-AC /0694801-015-AV

Permit Status: DRAFT AND DRAFT/PROPOSED  
Permit Activity: CONSTRUCTION  
Facility County: LAKE

Click on the following link to access the permit project documents:

[http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf\\_permit\\_zip\\_files/0694801.014.AC.D\\_pdf.zip](http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0694801.014.AC.D_pdf.zip) and

[http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf\\_permit\\_zip\\_files/0694801.015.AV.D\\_PDF.zip](http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0694801.015.AV.D_PDF.zip)

The Office of Permitting and Compliance is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at <http://www.dep.state.fl.us/air/emission/apds/default.asp>.

Permit project documents addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Office of Permitting and Compliance.

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

Regards,

**Lynn Searce**

Office of Permitting and Compliance (OPC)

Division of Air Resources Management

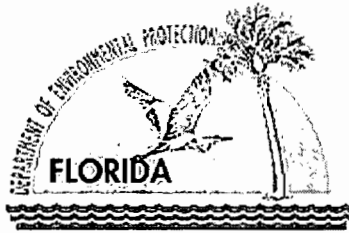
850-717-9025

## Scearce, Lynn

---

**From:** Thomas Grace [tgrace@caithnessenergy.com]  
**To:** Scearce, Lynn  
**Sent:** Monday, November 07, 2011 3:57 PM  
**Subject:** Read: 0694801-014-AC-PSD-FL-176D, Notice of Draft / 0694801-015-AV, Notice of Draft/Proposed, Lake Cogeneration

Your message was read on Monday, November 07, 2011 3:56:46 PM (GMT-05:00) Eastern Time (US & Canada).



**TECHNICAL EVALUATION  
&  
PRELIMINARY DETERMINATION**

**APPLICANT**

Lake Cogeneration, Ltd.  
39001 Golden Gem Drive  
Umatilla, Florida 32784

Lake Cogeneration Plant  
ARMS Facility ID No. 0694801

**PROJECT**

Project No. 0694801-014-AC (PSD-FL-176D)  
Application for Air Construction Permit  
Updated Air Construction Permit

**COUNTY**

Lake, Florida

**PERMITTING AUTHORITY**

Florida Department of Environmental Protection  
Division of Air Resource Management  
Office of Permitting and Compliance  
Chemicals and Combustion Key Industry Group  
2600 Blair Stone Road, MS#5505  
Tallahassee, Florida 32399-2400

November 7, 2011

## 1. GENERAL PROJECT INFORMATION

### Air Pollution Regulations

Projects at stationary sources with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish regulations regarding air quality as part of the Florida Administrative Code (F.A.C.), which includes the following applicable chapters: 62-4 (Permits); 62-204 (Air Pollution Control – General Provisions); 62-210 (Stationary Sources – General Requirements); 62-212 (Stationary Sources – Preconstruction Review); 62-213 (Operation Permits for Major Sources of Air Pollution); 62-296 (Stationary Sources – Emission Standards); and 62-297 (Stationary Sources – Emissions Monitoring). Specifically, air construction permits are required pursuant to Chapters 62-4, 62-210 and 62-212, F.A.C.

In addition, the U. S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 specifies New Source Performance Standards (NSPS) for numerous industrial categories. Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP) based on specific pollutants. Part 63 specifies NESHAP based on the Maximum Achievable Control Technology (MACT) for numerous industrial categories. The Department adopts these federal regulations in Rule 62-204.800, F.A.C.

### Glossary of Common Terms

Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of the permit.

### Facility Description and Location

Lake Cogeneration, Ltd. operates the Lake Cogeneration Plant, a combined cycle combustion turbine cogeneration power plant, which is categorized under Standard Industrial Classification code (SIC) No. 4931. The facility is located in Lake County at 39001 Golden Gem Drive in Umatilla, Florida. The UTM coordinates of the existing facility are Zone 17, 434 kilometer (km) East, and 3198.80 km North. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to Ambient Air Quality Standards (AAQS).

The facility consists of a fuel oil storage tank (EU-002) and two 50 megawatt (MW) General Electric Model LM6000 combustion turbine-electrical generator sets (EU-003 and EU-004). Each combustion turbine is equipped with an inlet air chiller system, a heat recovery steam generator (HRSG) with natural gas-fired duct burners and an exhaust stack. Steam is delivered from both units to a common steam turbine-electrical generator set with a nominal rating of 26.5 MW. The primary fuel is pipeline natural gas with low distillate oil as a restricted alternate fuel. A spray inter-cooling (SPRINT) system was installed on each of the combustion turbines in 2007. Nitrogen oxides (NO<sub>x</sub>) emissions are controlled with a water injection system. Carbon monoxide (CO) and volatile organic compounds (VOC) are controlled using oxidation catalyst system. A continuous emission monitoring system (CEMS) is installed on each unit for monitoring and reporting NO<sub>x</sub> emissions.

### Facility Regulatory Categories

- The facility does not operate units subject to the acid rain provisions of the Clean Air Act (CAA).
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The existing facility is a major stationary source of air pollution pursuant to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.
- The existing facility is not a major source of hazardous air pollutants (HAP).
- The combustion turbines are subject to Clean Air Interstate Rule (CAIR) set forth in Rule 62-296.470, F.A.C.
- The existing combined cycle combustion turbine are subject to the applicable federal NSPS provisions in Subpart A (General Provisions) and Subpart KKKK (Stationary Combustion Turbines) of 40 CFR 60.



### Permit History

The following permitting history summarizes the air construction permits and modification, revisions and amendments thereto since issuance of the original permit to the present action:

- *Permit No. AC35-196459 (PSD-FL-176)*: The original permit was issued on 11/20/1991. The applicant was authorized to construct the two combustion turbines, heat recovery steam generators with duct burners and a common steam turbine.
- *Amendment to Permit No. AC35-196459 (PSD-FL-176)*: On 03/10/1994, the original construction permit was revised for the following items:
  - Revised emissions Table 1A in Specific Condition 1;
  - Removed references to acceptable ambient concentrations (AAC) for beryllium, lead and mercury in Specific Condition 2;
  - Revised the maximum heat input rates based on the lower heating value while burning natural gas and distillate oil at compressor inlet condition of 51° F as well as 59° F (ISO conditions). It also revised the duct firing while burning natural gas and the limits in Specific Condition 6;
  - Removed references to an adjustment of NO<sub>x</sub> emissions based on ISO conditions including calculations in Specific Condition 13;
  - Modified Specific Condition 16 pertaining to the combustion control of CO emissions and providing a space suitable for the later installation of an oxidation catalyst; and
  - In Specific Condition 20, revised the compliance requirements in Subparts GG and Dc of 40 CFR 60 and Rule 17-296.800(2) (a), F.A.C.
- *Amendment to Permit No. AC35-196459 (PSD-FL-176)*: On 04/22/1994, the permit was amended to include a custom fuel monitoring schedule for SO<sub>2</sub> and NO<sub>x</sub> to demonstrate compliance with NSPS Subpart GG in 40 CFR 60.
- *Amendment to Permit No. AC35-196459 (PSD-FL-176)*: On 05/10/1994, the original construction permit was revised to allow additional time to complete the compliance testing for CO emissions.
- *Amendment to Permit No. AC35-196459 (PSD-FL-176A)*: On 08/03/1994, the original construction permit was extended until December 30, 1994 and revised to correct (reduce) the CO concentrations upon which mass emission limits were based.
- *Amendments to Permit No. AC35-196459 (PSD-FL-176A)*: On 12/28/1994 and 04/10/1995, the original construction permit was extended to 03/31/1995 and 06/30/1995, respectively.
- *Permit Amendment No. 0694801-003-AC*: On July 3, 1997, the original construction permit was amended to clarify that the ISO correction factor and requirement to test at four loads only applies to the NSPS Subpart GG provisions for NO<sub>x</sub>.
- *Air Construction Permit No. 0694801-008-AC (PSD-FL-176B)*: On 06/13/2007, a permit was issued to modify the combustion turbines as follows:
  - Installed the SPRINT system on the compressor of each combustion turbine to increase power output;
  - Increased the maximum heat input rate when firing natural gas from 423 to 425 MMBtu/hour per unit;
  - Increased the mass emission rate for CO and NO<sub>x</sub> emissions; and
  - Required additional compliance tests for CO and NO<sub>x</sub> emissions after completing construction of the SPRINT system and increasing the heat input rate.
- *Air Construction Permit Modification No. 0694801-010-AC (PSD-FL-176C)*: On 06/23/2009, the previous permit was revised to increase the maximum heat input rate when firing natural gas, install a CEMS for NO<sub>x</sub>, revise the averaging period for the NO<sub>x</sub> standard, and identify that the combustion turbines will now be subject to the new NSPS Subpart KKKK for new, modified and reconstructed combustion turbines.

## TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

---

- *Air Construction Permit No. 0694801-012-AC*: On 06/04/2010, this permit authorized installation of an oxidation catalyst system in the HRSG associated with each of the two combustion turbines.
- *Air Construction Permit Modification No. 0694801-014-AC (PSD-FL-176D)*: On February 1, 2011, the Department received an application to revise the past permits applicable to the existing Lake Cogeneration Plant as described below.

### Project Description

The applicant requests the following modifications of the past permits:

- Correct the nominal electrical production rate from 52 MW to 50 MW;
- Include a performance curve identifying maximum heat input rate based on the fluctuating compressor inlet temperature;
- Correct and update the allowable emission limits;
- Remove the distinction between the normal operating mode and the SPRINT mode;
- Include authorization to replace limited components for maintenance and repairs of the combined cycle combustion turbine system; and,
- Change the annual test schedule from July 15<sup>th</sup> to within the federal fiscal year.

This application is being processed concurrently with an early Title V air operation permit renewal to incorporate the air construction permit changes.

## 2. PSD APPLICABILITY

### General PSD Applicability

The Department regulates major stationary sources in accordance with Florida's PSD program pursuant to Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for these regulated pollutants.

PSD pollutants include: carbon monoxide (CO); nitrogen oxides (NO<sub>x</sub>); sulfur dioxide (SO<sub>2</sub>); particulate matter (PM); PM smaller than 10 micrometers (PM<sub>10</sub>); volatile organic compounds (VOC); lead (Pb); Fluorides (F); sulfuric acid mist (SAM); total reduced sulfur (TRS), including H<sub>2</sub>S; municipal waste combustor (MWC) organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans (D/F); MWC metals measured as PM; MWC acid gases measured as SO<sub>2</sub> and hydrogen chloride (HCl); and mercury (Hg).

As defined in Rule 62-210.200(189)(a)1, F.A.C., a "major stationary source" (major PSD source) is any of 28 listed stationary sources of air pollutants which emits, or has the potential to emit, 100 tons per year (TPY) or more of any PSD pollutant. [Link to Rule 62-210, F.A.C.](#)

The list given in the citation includes the category of "fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input". The Lake Cogeneration Facility is a major stationary source based on its actual emissions and its potential to emit PSD pollutants. The major stationary source threshold for source categories not on the cited list is 250 TPY or more of any PSD pollutant.

For major stationary sources, PSD applicability is based on emissions thresholds known as the significant emission rates (SER) as defined in Rule 62-210.200 (Definitions), F.A.C. Emissions of PSD pollutants from the project exceeding these SER are considered "significant" and BACT must be employed to minimize emissions of each PSD pollutant and an air quality impact analysis must be conducted for the PSD pollutants for which AAQS are defined. SER also means any emissions rate or any net emissions increase of a PSD pollutant associated with a major stationary source or major modification which would construct within 10 kilometers of a Class I area and have an impact on such area equal to or greater than 1 gram per cubic meter, 24-hour average.

Although a facility may be "major" for only one PSD pollutant, a project must include BACT controls for any PSD pollutant that exceeds the corresponding SER given in Table 1.

## TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

**Table 1 - List of SER by PSD-Pollutant<sup>1, 4</sup>**

Pollutant	SER (TPY)	Pollutant	SER (TPY)
CO	100	NO <sub>x</sub>	40
PM/PM <sub>10</sub> <sup>2</sup>	25/15	Ozone (VOC) <sup>3</sup>	40
Ozone (NO <sub>x</sub> ) <sup>3</sup>	40	SAM	7
SO <sub>2</sub>	40	F	3
Pb	0.6	TRS	10
H <sub>2</sub> S	10	Hg	0.1

1. Excluding those defined exclusively for MWC and MSW landfills.

2. PM<sub>2.5</sub> is also a PSD pollutant, but an SER has not yet been defined in the Department's rules. It is regulated by its precursors and surrogates (e.g. PM/PM<sub>10</sub> NH<sub>3</sub>, SO<sub>2</sub> and NO<sub>x</sub>).

3. Ozone (O<sub>3</sub>) is regulated by its precursors (VOC and NO<sub>x</sub>).

4. There is a federal SER of 75,000 TPY for Greenhouse Gases (GHG) as carbon dioxide equivalent (CO<sub>2</sub>e) that has not been incorporated into Department rules. However, the applicability to the CO<sub>2</sub> component of GHG emissions from bioenergy and biogenic stationary sources was recently deferred by EPA until the second half of 2014. Refer to: [Link to Final CO<sub>2</sub> PSD Deferral](#).

PM<sub>2.5</sub> is also a Federal PSD pollutant and the Department is in the process of adopting a SER of 10 TPY. Refer to [Link to PM<sub>2.5</sub> Rule Development](#). Until the rule is finalized, projects in Florida are not subject to a SER for PM<sub>2.5</sub>.

### PSD Applicability for Project

The project is located in Lake County which is in an area that is currently in attainment with the AAQS or is otherwise designated as unclassifiable. The proposed project will not increase emissions for any PSD pollutant; therefore, the project is not subject to a PSD preconstruction review.

### 3. DEPARTMENT REVIEW

#### Nominal Electrical Production Rate

The applicant indicated that the nominal electrical production rate after completing the SPRINT project was actually 50 MW and not 52 MW. The draft permit reflects this change.

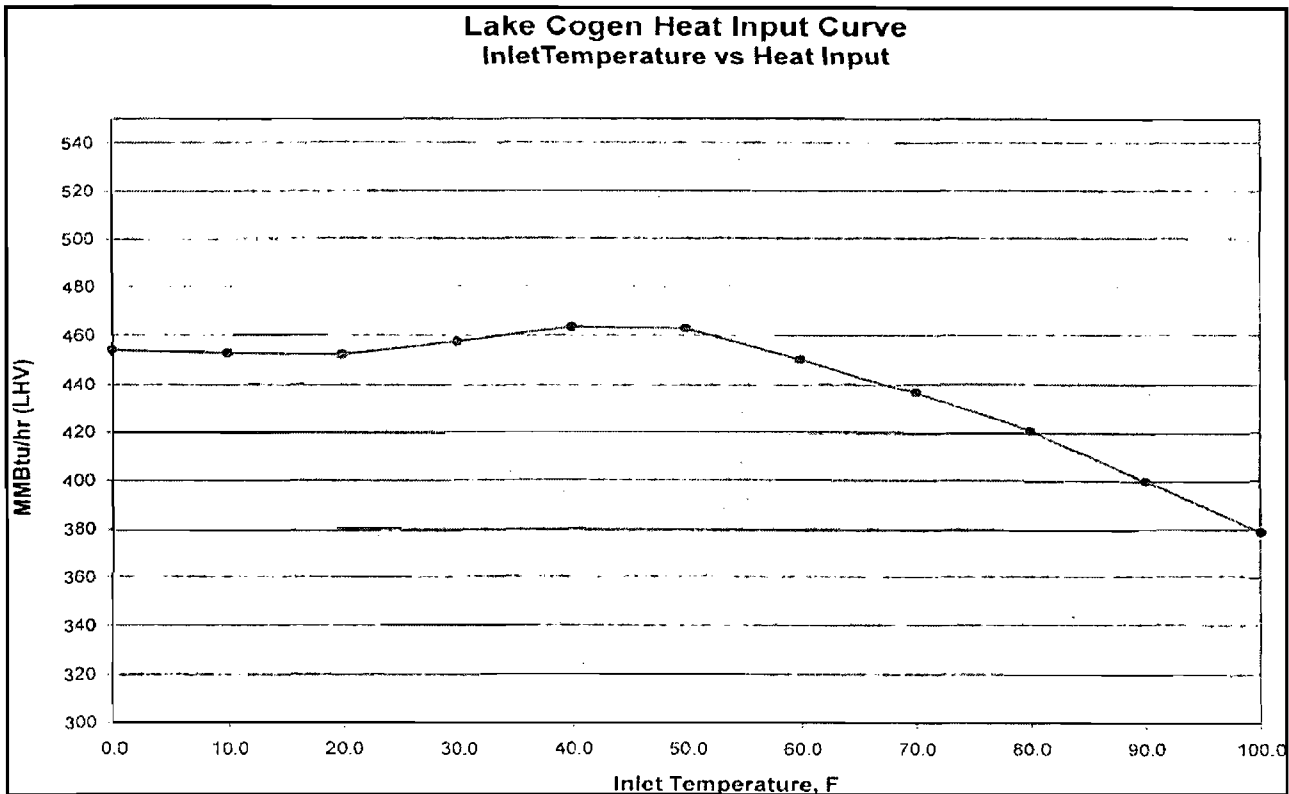
#### Permitted Capacity

The applicant initially requested removal of the references to 59 degrees Fahrenheit (°F). However, the Department explained that this represented ISO conditions, which are identified in the NSPS provisions for combustion turbines. So, instead, the references to 51° F were removed to clarify the permit. Mass emission rates are a function of the heat input rate and require a performance curve to identify emissions for a given set of operational conditions. For combustion turbines (CT), the maximum heat input rate varies with the compressor (CT) inlet temperature instead of limits in terms of mass emissions, which is the justification for specifying emissions limits in terms of concentration corrected to 15 % oxygen (O<sub>2</sub>). Therefore, reference to the maximum heat input rates have been removed and a performance curve, Heat Input vs. CT Inlet Temperature Curve, has been included identifying the maximum heat input rate at a given inlet temperature, in accordance with Figure 1.

The performance curve identifies the nominal heat input values based on the lower heating value (LHV) of each fuel, 100% load, and inlet conditions of 59° F temperature, 60% relative humidity, and 14.7 pounds per square inch absolute (psia). These nominal heat input rates will vary depending upon inlet conditions and the combustion turbine characteristics. The corresponding "allowable" mass emissions rates will remain the same and there will not be an increase in emissions for any PSD pollutant. Therefore, no new air quality modeling analysis is required.

#### Permitted Capacity with/without SPRINT Operation

The earlier conversion from the LM6000PA to the LM6000PC combustion turbines provided the capability of operating at higher inlet temperatures in either SPRINT or non-SPRINT mode. Although the combustion turbine typically operates with the SPRINT system on, it is capable of operating without the SPRINT system. Therefore, the applicant has requested that the distinction between the normal operating mode and the SPRINT mode be removed.



**Figure 1 - Heat Input vs. CT Inlet Temperature Curve**

### Component Replacement

The combustion turbine system generally consists of the following components: gas turbine, accessory drive system, air inlet and filtration system, fuel delivery system, cooling system, lubrication system, control system, starting system and exhaust system with stack. This aero-derivative gas turbine is designed with modular components to facilitate quick repairs. Common “wear items” include compressor vanes, turbine nozzles, compressor blades, turbine blades, fuel nozzles, combustion chambers and seals. The concept of modular design extends to the complete replacement of major components of the gas turbine. Therefore, the applicant has requested authorization to replace some of the components without acquiring a permit.

The Department agrees that the replacement of certain components will not require an application for an air construction permit provided the following requirements are met:

- The components (e.g., combustors and high-speed turbines) shall be replaced with equivalent “like-kind” equipment. Replacement components shall not increase the maximum heat input rate, capacity or emissions from the combustion turbine. Replacement components shall be designed to comply with the emissions standards specified in this permit.
- With the exception of leased engines, the permittee shall conduct emissions stack test to demonstrate compliance with the emission standards for CO and visible emissions within 90 days of replacing a gas turbine. The permittee shall comply with the requirements for notification, test methods, test procedures, and reporting required by this permit.
- To up-rate the gas turbine or increase the maximum heat input rate or capacity above that represented on Figure 1 above, Heat Input vs. CT Inlet Temperature Curve (attached as Figure 1 to the permit), the permittee shall submit an application for an air construction permit.

# TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

## Allowable Emission Limit Table

The following table included in Condition III.A.10 of the permit contains the maximum allowable emissions standards based on the original and subsequent permits and modifications thereto.

Pollutant	Fuel <sup>b</sup>	Source <sup>a, c</sup>	Maximum Allowable Emission Standards <sup>a, d</sup>	Equivalent Emissions @ 59°F <sup>k</sup>	
				lb/hour	TPY <sup>k</sup>
NO <sub>x</sub> <sup>e</sup>	NG	CT	BACT Limit: 25 ppmvd at 15% O <sub>2</sub> as determined by a 24-hour CEMS block average	82.7	422.1
		DB	0.1 lb/MMBtu	18.0	
		CT & DB	BACT Limit: 25 ppmvd at 15% O <sub>2</sub> as determined by a 24-hour CEMS block average	100.7	
		ALL	NSPS Subpart KKKK Limit: 42 ppmvd at 15% O <sub>2</sub> as determined a 30-day rolling CEMS average.	---	
	DFO	CT	BACT Limit: 42 ppmvd at 15% O <sub>2</sub> as determined by a 24-hour CEMS block average	143.9	
			NSPS Subpart KKKK limit: 96 ppmvd at 15% O <sub>2</sub> as determined a 30-day rolling CEMS average.	---	
CO <sup>f</sup>	NG	CT	BACT Limit: 28 ppmvd at 15% O <sub>2</sub>	54.6	341.6
		DB	BACT Limit: 0.2 lb/MMBtu	36.0	
		CT & DB	---	90.6	
	DFO	CT	BACT Limit: 18 ppmvd at 15% O <sub>2</sub>	33.0	
PM/PM <sub>10</sub> <sup>g</sup>	NG	CT	BACT Limit: 0.0065 lb/MMBtu	5.0	31.3
		DB	BACT Limit: 0.006 lb/MMBtu	2.6	
		CT & DB	---	7.6	
	DFO	CT	BACT Limit: 0.026 lb/MMBtu	20.0	
SO <sub>2</sub> <sup>h</sup>	NG	CT & DB	Limit: 1 grain S/100 scf of natural gas, annual average based on vendor data	---	15.0
	DFO	CT	Limit: 0.05% sulfur by weight	---	
VOC <sup>i</sup>	NG	CT	There is no standard for VOC emissions.	3.3	30.8
		DB	There is no standard for VOC emissions.	5.4	
		CT & DB	There is no standard for VOC emissions.	8.7	
	DFO	CT	There is no standard for VOC emissions.	8.3	
SAM	DFO	CT	Limit: 0.05% sulfur by weight	---	0.8
Opacity <sup>j</sup>	ALL	CT & DB	BACT Limit: 10% Opacity	---	---

- a. CT = 2 combustion turbines, DB = 2 duct burners. The allowable emissions standards apply to each unit at all times.
- b. NG = natural gas, DFO = distillate fuel oil
- c. As specified by this permit, compliance with the Maximum Allowable Emission Standards shall be demonstrated for CT limits and CT&DB limits based on data from CEMS, stack tests or data from the annual RATA.
- d. These are the Maximum Allowable Emission Standards that shall never be exceeded at any temperature and/or operating configuration.
- e. Continuous compliance with the 24-hour block and 30-day rolling averages shall be demonstrated with data collected by the required CEMS. [Rule 62-212.400(BACT), F.A.C. and NSPS Subpart KKKK in 40 CFR 60]
- f. Compliance with the CO emissions standard shall be determined by EPA Method 10. [Rule 62-212.400(BACT), F.A.C.]
- g. As determined by fuel specifications, emissions of PM/PM<sub>10</sub> shall be minimized by the use of natural gas as the primary fuel with a maximum sulfur content of 1 grain S/100 scf and the limited use of distillate oil with a maximum sulfur content of 0.05% by weight. [Rule 62-212.400(BACT), F.A.C.]
- h. As determined by fuel specifications, emissions of SO<sub>2</sub> shall be minimized by the use of natural gas as the primary fuel with a maximum sulfur content of 1 grain S/100 scf and the limited use of distillate oil with a maximum sulfur content of 0.05% by weight. Pursuant NSPS Subpart KKKK provisions in 40 CFR 60, the maximum sulfur content of any fuel fired in the combustion turbine shall not exceed 0.06 lb SO<sub>2</sub>/MMBtu. This data shall be submitted with the annual operating report.
- i. There is no standard for VOC emissions. *{Permitting Note: Based on vendor data and installation of the oxidation catalyst, estimated maximum VOC emissions are less than 40 tons per year for the project to avoid PSD preconstruction review.}*
- j. Compliance with the opacity standard shall be determined by EPA Method 9 observations. [Rule 62-212.400(BACT), F.A.C.]
- k. The "Equivalent Emissions @ 59°F" are the total emissions from Units 1 and 2. Estimated annual emissions are for informational purposes only and are based on the most stringent emissions rate when the CT is firing natural gas for 8,520 hours/year, the emissions while firing DFO for 240 hours/year and DB emissions firing only natural gas for approximately 5,833 hours/year.

### **Annual Test Schedule**

The current permit requires an annual test to be conducted within 60 days prior to July 15<sup>th</sup>. However, Rule 62-297.310(7), F.A.C., allows compliance testing to be conducted within the federal fiscal year (October 1<sup>st</sup> to September 30<sup>th</sup>). The permit was revised accordingly.

### **Conclusion**

The applicant's requests are acceptable. An air construction permit (draft attached) will be issued for the Lake Cogeneration facility that replaces and supersedes the previous air construction permit No. AC35-196459 (PSD-FL-176) and subsequent permits and modifications thereto. It will include updated equipment specifications and regulatory requirements. The requirements of the original best available control technology (BACT) determination issued on November 20, 1991 pursuant to the rules for the Prevention of Significant Deterioration (PSD) are maintained and re-established therein. The updated permit will also be consistent with more recent air construction permits for combined cycle combustion turbines, including but not limited to:

- Including a performance curve identifying maximum heat input rate based on the fluctuating compressor inlet temperature;
- Identifying the allowable emission standards and the equivalent emissions given at an inlet temperature of 59 °F in Specific Condition III.A.10 of this permit.
- Identifying the maximum fuel sulfur specification as the limitations for SO<sub>2</sub> and PM/PM<sub>10</sub> emissions.
- Clarifying that the VOC emissions are "estimated maximum emissions" and not limits since total VOC emissions are much less than the PSD significant emissions rates following the installation of an oxidation catalyst.
- Clarifying that compliance with the NO<sub>x</sub> standards is based on data collected by the required CEMS and not stack testing.
- Clarifying that the required annual compliance tests are for CO and visible emissions.

Although the proposed project does not increase the permitted capacity or emissions, the Department will require a 30-day comment period concurrent with that of the renewed Title V air operation permit.

### **4. PRELIMINARY DETERMINATION**

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

# DRAFT

## PERMITTEE

Lake Cogeneration, Ltd.  
39001 Golden Gem Drive  
Umatilla, FL 32784

Air Permit No. 0694801-014-AC  
PSD-FL-176D

Authorized Representative:  
Mr. James Miller, Plant Manager

Lake Cogeneration Facility  
Updated Air Construction Permit

## PROJECT

This Final air construction permit No. 0694801-014-AC (PSD-FL-176D) for the Lake Cogeneration Facility replaces and supersedes the previous air construction permit No. AC35-196459 (PSD-FL-176) and modifications thereto. It includes updated equipment specifications and regulatory requirements. The requirements of the original best available control technology (BACT) determination issued on November 20, 1991 pursuant to the rules for the Prevention of Significant Deterioration (PSD) are maintained and re-established herein.

The proposed permit applies to the existing Lake Cogeneration Facility, which is a nominal 126.5 megawatts (MW) power plant categorized under Standard Industrial Classification No. 4931. The existing facility is located in Lake County at 39001 Golden Gem Drive in Umatilla, Florida. The UTM coordinates of the existing facility are Zone 17, 434.00 kilometers (km) East, and 3198.80 km North.

This final permit is organized into the following sections: Section 1 (General Information); Section 2 (Administrative Requirements); Section 3 (Emissions Unit Specific Conditions); Section 4 (Appendices). Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of Section 4 of this permit.

## STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. and is not subject to the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Executed in Tallahassee, Florida

(DRAFT)

Jeffery F. Koerner, Program Administrator  
Office of Permitting and Compliance  
Division of Air Resource Management

(Date)

## DRAFT PERMIT

---

### CERTIFICATE OF SERVICE

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

Mr. James Miller, Lake Cogeneration Facility: ([jmiller@caithnessenergy.com](mailto:jmiller@caithnessenergy.com))

Mr. Thomas Grace, Caithness Energy: ([tgrace@caithnessenergy.com](mailto:tgrace@caithnessenergy.com))

Mr. Scott Osbourn, Golder Associates: ([sosbourn@golder.com](mailto:sosbourn@golder.com))

Ms. Caroline Shine, DEP CD Office: ([caroline.shine@dep.state.fl.us](mailto:caroline.shine@dep.state.fl.us))

Ms. Ana Oquendo, US EPA Region 4: ([oquendo.ana@epa.gov](mailto:oquendo.ana@epa.gov))

Ms. Heather Ceron, US EPA Region 4: ([ceron.heather@epa.gov](mailto:ceron.heather@epa.gov))

Ms. Katy Forney, EPA Region 4: ([forney.kathleen@epa.gov](mailto:forney.kathleen@epa.gov))

Ms. Barbara Friday, DEP OPC: ([barbara.friday@dep.state.fl.us](mailto:barbara.friday@dep.state.fl.us))

Ms. Lynn Searce, DEP OPC: ([lynn.searce@dep.state.fl.us](mailto:lynn.searce@dep.state.fl.us))

Clerk Stamp

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

(DRAFT)

\_\_\_\_\_  
(Clerk)

\_\_\_\_\_  
(Date)



## SECTION 1. GENERAL INFORMATION (DRAFT)

### FACILITY DESCRIPTION

The existing facility is a nominal 126.5 megawatts (MW) cogeneration plant, which consists of two nominal 50 MW General Electric (GE) LM-6000 combined cycle combustion turbines (EU-003 and EU-004). Each combustion turbine (CT) is equipped with an air inlet chiller and natural gas-fired duct burner and exhausts through a heat recovery steam generator (HRSG) stack. The two HRSG share a single 26.5 MW steam turbine-electric generator. The primary fuel is pipeline natural gas and low sulfur distillate oil as a restricted alternate fuel. Nitrogen oxides (NO<sub>x</sub>) are reduced with a water injection system. In 2007, a spray inter-cooling (SPRINT) system was installed on each of the combustion turbines. Subsequently, a continuous emission monitoring system (CEMS) for monitoring and reporting NO<sub>x</sub> emissions was also installed on each unit. Carbon monoxide (CO) and volatile organic compounds (VOC) are controlled using oxidation catalyst system. The existing combustion turbines are subject to the applicable NSPS standards in Subpart A (General Provisions) and Subpart KKKK (Stationary Combustion Turbines). The facility also includes an emergency generator and a fire pump (EU 005 and EU 006).

Lake Cogeneration is not subject to the Acid Rain Program because steam is being directed to an independent steam host (adjacent citrus process facility), which classifies it as a "Qualified Facility". This permit affects the following emissions units:

Facility ID No. 0694801	
ID No.	Emission Unit (EU) Description
002	Fuel Oil Tank
003	Combined Cycle Unit 1
004	Combined Cycle Unit 2

### PROJECT DESCRIPTION

The purpose of this project is to modify the original Permit No. PSD-FL-176 or subsequent modifications thereto for the following items at the existing Lake Cogeneration Plant:

- Correct the nominal electrical production rate of each combustion turbine-electric generator from 52 MW to 50 MW;
- Revise to include a performance curve identifying maximum heat input rate based on the fluctuating compressor inlet temperature;
- Correct and update the allowable emission limits;
- Remove the distinction between the normal operating mode and the SPRINT mode;
- Include authorization to replace limited components for maintenance and repairs of the combined cycle combustion turbine system;
- Change the annual test schedule from July 15<sup>th</sup> to within the federal fiscal year; and
- Update the permit for to be more consistent with recent air construction permits for combined cycle combustion turbines.

### FACILITY REGULATORY CLASSIFICATION

- The existing facility is not a major source of hazardous air pollutants (HAP).
- The existing facility has no units subject to the acid rain provisions.
- The existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The existing facility is a PSD major stationary source of air pollution pursuant to Rule 62-212.400, F.A.C.
- The existing combined cycle combustion turbines are subject to Clean Air Interstate Rule (CAIR) set forth in Rule 62-296.470, F.A.C.

## **SECTION 1. GENERAL INFORMATION (DRAFT)**

---

- The existing combined cycle combustion turbines are subject to the applicable federal New Source Performance Standards (NSPS) in Subpart A (General Provisions) and Subpart KKKK (Stationary Combustion Turbines) of 40 CFR 60.
- The existing reciprocating internal combustion engines (RICE) are subject to the applicable federal National Emissions Standards for Hazardous Air Pollutants (NESHAP) in Subpart A (General Provisions) and Subpart ZZZZ (Stationary Reciprocating Internal Combustion Engines)

## SECTION 2. ADMINISTRATIVE REQUIREMENTS (DRAFT)

---

1. Permitting Authority: The Permitting Authority for this project is the Office of Permitting and Compliance in the Division of Air Resource Management of the Department. The mailing address for the Office of Permitting and Compliance is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400.
2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section in the Department's Central District Office at 3319 Maguire Boulevard, Suite 232, Orlando, FL 32803-3767.
3. Appendices: The following Appendices are attached as part of this permit: Appendix A (Citation Formats and Glossary of Common Terms), Appendix B (General Conditions), Appendix C (Common Conditions), Appendix D (Common Testing requirements), Appendix E (CEMS Requirements), Appendix F (NSPS Subpart A), Appendix G (Subpart KKKK), and Appendix H (Heat Input vs. CT Inlet Temperature Curve).
4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296 and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
6. Modifications: No emissions unit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1) (a), F.A.C.]
7. Source Obligation: At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by 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)(c), F.A.C.]
8. Actual Emissions Reporting: The previous permit for the SPRINT conversion project was based on an analysis that compared baseline actual emissions with projected actual emissions and avoided the requirements of subsection 62-212.400(4) through (12), F.A.C. for several pollutants. Therefore, pursuant to Rule 62-212.300(1)(e), F.A.C., the permittee is subject to the following monitoring, reporting and recordkeeping provisions.
  - a. The permittee shall monitor the emissions of any PSD pollutant that the Department identifies could increase as a result of the construction or modification and that is emitted by any emissions unit that could be affected; and, using the most reliable information available, calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change. Emissions shall be computed in accordance with the provisions in Rule 62-210.370, F.A.C., which are provided in Appendix C of this permit.
  - b. The permittee shall report to the Department within 60 days after the end of each calendar year during the 5-year period setting out the unit's annual emissions during the calendar year that preceded submission of the report. The report shall contain the following:
    - 1) The name, address and telephone number of the owner or operator of the major stationary source;
    - 2) The annual emissions as calculated pursuant to the provisions of 62-210.370, F.A.C., which are provided in Appendix C of this permit;

## SECTION 2. ADMINISTRATIVE REQUIREMENTS (DRAFT)

---

- 3) If the emissions differ from the preconstruction projection, an explanation as to why there is a difference; and
  - 4) Any other information that the owner or operator wishes to include in the report.
- c. The information required to be documented and maintained pursuant to subparagraphs 62-212.300(1)(e)1 and 2, F.A.C., shall be submitted to the Department, which shall make it available for review to the general public.

For the previously approved SPRINT conversion project, the permittee is required to annually report actual CO and NO<sub>x</sub> emissions from Unit 1 (EU-003) and Unit 2 (EU-004) for a period of five years. This reporting requirement begins the first full calendar year of operation once the SPRINT project is complete. "Baseline actual emissions" (2-year average) for Unit 1 and Unit 2 combined are 180 tons per year of CO and 272 tons per year of NO<sub>x</sub>. The SPRINT project was complete in 2007 and the first reporting year was 2008. [Rules 62-212.300(1)(e) and 62-210.370, F.A.C.]

### SECTION III. SPECIFIC CONDITIONS FOR EMISSIONS UNITS

#### Subsection A. Combined Cycle Units

This section of the permit addresses the following emissions units:

ID No.	Emission Unit Description
002	Distillate Oil Tank (170,000 gallon)
003	Combined Cycle Unit 1 - Combustion turbine-electrical generator set (50 MW) with natural gas-fired HRSG*
004	Combined Cycle Unit 2 - Combustion turbine-electrical generator set (50 MW) with natural gas-fired HRSG*

\* Units 1 and 2 share a common steam turbine-electrical generator set rated at 26.5 MW.

{Permitting Note: These emissions units are subject to the following primary regulations:

- In accordance with Rule 62-212.400(PSD), F.A.C., the above emission units are subject to Best Available Control Technology (BACT) determinations for the following pollutants: CO, NO<sub>x</sub>, particulate matter (PM), particulate matter with a mean particle diameter of 10 microns or less (PM<sub>10</sub>) and sulfur dioxide (SO<sub>2</sub>). The requirements of the original BACT determination issued on November 20, 1991 pursuant to the PSD rules are maintained and re-established in Condition III.A.10 of this permit.
- The combustion turbines are subject to Clean Air Interstate Rule (CAIR) set forth in Rule 62-296.470, F.A.C.
- The combustion turbines are not subject to the Acid Rain Program because steam is being directed to an independent steam host (adjacent citrus processing facility), which is classified as a "Qualified Facility".
- The combined cycle combustion turbines are subject to the applicable federal NSPS provisions in Subpart A (General Provisions) and Subpart KKKK (Stationary Combustion Turbines) of 40 CFR 60.}

#### PREVIOUS APPLICABLE REQUIREMENTS

1. Previous Air Construction Permits: This Final air construction permit No. 0694801-014-AC (PSD-FL-176D) replaces and supersedes the original air construction permit No. AC35-196459 (PSD-FL-176) and modifications thereto. [Application; Rules 62-4.080, 62-210.300, 62-212.300 and 62-212.400, F.A.C.]

#### EQUIPMENT AND PERFORMANCE RESTRICTIONS

2. Combined Cycle Combustion Turbine System: The permittee is authorized to construct, operate and maintain as combined cycle combustion turbine system consisting of two nominal 50 MW combustion turbines (GE LM6000-PC-SPRINT) and a heat recovery steam generator with duct burner. The combustion turbine system generally consists of the following components: gas generator, accessory drive system, air inlet and filtration system, fuel delivery system, cooling system, lubrication system, control system, starting system and exhaust system with stack. This aero-derivative gas turbine is designed with modular components to facilitate quick repairs. Common "wear items" include compressor vanes, turbine nozzles, compressor blades, turbine blades, fuel nozzles, combustion chambers, seals, and shaft packing. The concept of modular design extends to the complete replacement of major components of the gas turbine. Replacements are authorized provided the following requirements are met.
  - a. The "hot section" components (e.g., combustors and high-speed turbines including blades, nozzles and other components) shall be replaced with equivalent "like-kind" equipment. Replacement components shall not increase the maximum heat input rate, capacity or emissions from the combustion turbine. Replacement components shall be designed to comply with the emissions standards specified in this permit.
  - b. With the exception of leased engines, the permittee shall conduct emissions stack test to demonstrate compliance with the emission standards for CO and visible emissions within 90 days of replacing a gas turbine. The permittee shall comply with the requirements for notification, test methods, test procedures, and reporting required by this permit.
  - c. To up-rate the gas turbine or increase the maximum heat input rate or capacity, the permittee shall submit an application for an air construction permit.

## SECTION III. SPECIFIC CONDITIONS FOR EMISSIONS UNITS

### Subsection A. Combined Cycle Units

[Application and Design]

3. Authorized Fuels:

a. *Natural gas.*

(1) Natural Gas, primary fuel.

(2) The maximum sulfur content of natural gas shall not exceed 1 grain sulfur (S)/100 scf based on an annual average of gas pipeline data (or fuel vendor analysis).

b. *Distillate Fuel Oil.*

(1) Maximum distillate fuel oil consumption shall not exceed either of the following limitations: 2,921 gallons/hour/CT; 701,050 gallons/year/CT.

(2) Maximum annual firing using distillate fuel oil shall not exceed an equivalent of 10 days (240 hours) per year at full load.

(3) Maximum sulfur content in the oil shall not exceed 0.05 percent by weight.

*{Permitting Note: The lower heating value (LHV) of natural gas is approximately 940 million British thermal units (MMBtu) per million cubic feet (MMcf) of gas. The LHV of distillate oil is approximately 135 MMBtu/1000 gallons. In accordance with NSPS Subpart KKKK, the maximum sulfur content of any fuel fired in the combustion turbine shall not exceed 0.06 pounds (lb) SO<sub>2</sub>/MMBtu.}*

[Design; Rule 62-212.400(BACT), F.A.C.; NSPS 40 CFR 60, Subpart KKKK]

4. Distillate Oil Tank: Emission Unit 002 is a 170,000 gallon distillate oil storage tank. *{Permitting Note: Based on changes to NSPS Subpart Kb (Volatile Organic Liquid Storage Vessels) in 40 CFR 60 made on October 15, 2003, the Subpart does not apply to storage vessels with a capacity greater than or equal to 39,890 gallons storing a liquid with a maximum true vapor pressure less than 0.51 pounds per square inch absolute (psia). The tank permitted stores distillate oil, which has a vapor pressure of approximately 0.009 psia at 70° Fahrenheit (F). This is well below the vapor pressure specified in Subpart Kb for this size tank and shows that distillate oil is not considered to be volatile. Therefore, the tank is considered an unregulated emissions unit.}* [Original Design]

5. Hours of Operation: Notwithstanding the fuel consumption limits, the combustion turbines may operate continuously (8,760 hours per year). [Application; Rule 62-210.200, (PTE), F.A.C.]

6. Permitted Capacity – Combustion Turbine: The heat input to the combustion turbines are approximately represented on the associated heat input curve attached to this permit as Appendix H – Heat Input vs. CT Inlet Temperature Curve. The nominal heat input values are based on the LHV of each fuel, 100 percent (%) load, and inlet conditions of 59° F temperature, 60% relative humidity, and 14.7 psia. These nominal heat input rates will vary depending upon inlet conditions and the combustion turbine characteristics. [Design and Application; Rule 62-210.200, (PTE), F.A.C.]

7. Permitted Capacity – HRSG Duct Burners: When the combustion turbines are firing natural gas, the permittee is authorized to operate the HRSG duct burners, which shall only fire natural gas. The permittee is not authorized to operate the duct burners when the combustion turbine is firing distillate oil. The annual heat input rate to the HRSG duct burners shall not exceed 525,000 MMBtu/year/HRSG-duct burner (equivalent to approximately 5,833 hours/year), based upon a maximum heat input rate not to exceed 90 MMBtu/hour (HHV).

[Design and Application; Rule 62-210.200, (PTE), F.A.C.]

### AIR POLLUTION CONTROL EQUIPMENT

8. Oxidation Catalyst: The permittee shall install, operate and maintain a catalytic oxidation system in the HRSG associated with each combustion turbine to control CO emissions. *{Permitting Note: The expected*

## SECTION III. SPECIFIC CONDITIONS FOR EMISSIONS UNITS

### Subsection A. Combined Cycle Units

*reduction in CO emissions are between 50% and 70% depending on the inlet concentration and exhaust gas temperature.*} [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

9. **Water Injection:** The permittee shall install, tune, operate and maintain a water injection system to control NO<sub>x</sub> emissions from the combustion turbine when firing either fuel. Data shall be maintained to correlate the NO<sub>x</sub> CEMS results to the water-to-fuel ratio monitoring results. Data for the water-to-fuel ratio shall be used to demonstrate compliance with the NO<sub>x</sub> standards if the NO<sub>x</sub> CEMS is not available. This monitoring shall be conducted consistent with the NSPS KKKK provisions.  
[Rule 62-212.400(BACT), F.A.C. and NSPS 40 CFR 60, Subpart KKKK]

### EMISSIONS STANDARDS

10. **Emissions Standards:** Emissions from each combustion turbine (CT) and HRSG duct burner (DB) shall not exceed the following standards:

Pollutant	Fuel <sup>b</sup>	Source <sup>a, c</sup>	Maximum Allowable Emissions Standards <sup>a, d</sup>	Equivalent Emissions @ 59°F <sup>k</sup>	
				lb/hour	TPY <sup>k</sup>
NO <sub>x</sub> <sup>e</sup>	NG	CT	BACT Limit: 25 ppmvd at 15% O <sub>2</sub> as determined by a 24-hour block CEMS average	82.7	422.1
		DB	0.1 lb/MMBtu	18.0	
		CT & DB	BACT Limit: 25 ppmvd at 15% O <sub>2</sub> as determined by a 24-hour CEMS block average	100.7	
		ALL	NSPS Subpart KKKK Limit: 42 ppmvd at 15% O <sub>2</sub> as determined a 30-day rolling CEMS average.	---	
	DFO	CT	BACT Limit: 42 ppmvd at 15% O <sub>2</sub> as determined by a 24-hour CEMS block average	143.9	
			NSPS Subpart KKKK limit: 96 ppmvd at 15% O <sub>2</sub> as determined a 30-day rolling CEMS average.	---	
CO <sup>f</sup>	NG	CT	BACT Limit: 28 ppmvd at 15% O <sub>2</sub>	54.6	341.6
		DB	BACT Limit: 0.2 lb/MMBtu	36.0	
		CT & DB	---	90.6	
	DFO	CT	BACT Limit: 18 ppmvd at 15% O <sub>2</sub>	33.0	
PM/PM <sub>10</sub> <sup>g</sup>	NG	CT	BACT Limit: 0.0065 lb/MMBtu	5.0	31.3
		DB	BACT Limit: 0.006 lb/MMBtu	2.6	
		CT & DB	---	7.6	
	DFO	CT	BACT Limit: 0.026 lb/MMBtu	20.0	
SO <sub>2</sub> <sup>h</sup>	NG	CT & DB	Limit: 1 grain S/100 scf of natural gas, annual average based on vendor data	---	15.0
	DFO	CT	Limit: 0.05% sulfur by weight	---	
VOC <sup>i</sup>	NG	CT	There is no standard for VOC emissions	3.3	30.8
		DB	There is no standard for VOC emissions	5.4	
		CT & DB	There is no standard for VOC emissions	8.7	
	DFO	CT	There is no standard for VOC emissions	8.3	
SAM	DFO	CT	Limit: 0.05% sulfur by weight	---	0.8
Opacity <sup>j</sup>	ALL	CT & DB	BACT Limit: 10% Opacity	---	---

a. CT = 2 combustion turbines, DB = 2 duct burners.

### SECTION III. SPECIFIC CONDITIONS FOR EMISSIONS UNITS

#### Subsection A. Combined Cycle Units

The allowable emissions standards apply to each unit at all times.

- b. NG = natural gas, DFO = distillate fuel oil
- c. As specified by this permit, compliance with the Maximum Allowable Emission Standards shall be demonstrated for CT limits and CT&DB limits based on data from CEMS, stack tests or data from the annual RATA.
- d. These are the Maximum Allowable Emission Standards that shall never be exceeded at any temperature and/or operating configuration.
- e. Continuous compliance with the 24-hour block and 30-day rolling averages shall be demonstrated with data collected by the required CEMS. [Rule 62-212.400(BACT), F.A.C. and NSPS Subpart KKKK in 40 CFR 60]
- f. Compliance with the CO emissions standard shall be determined by EPA Method 10. [Rule 62-212.400(BACT), F.A.C.]
- g. As determined by fuel specifications, emissions of PM/PM<sub>10</sub> shall be minimized by the use of natural gas as the primary fuel with a maximum sulfur content of 1 grain S/100 scf and the limited use of distillate oil with a maximum sulfur content of 0.05% by weight. [Rule 62-212.400(BACT), F.A.C.]
- h. As determined by fuel specifications, emissions of SO<sub>2</sub> shall be minimized by the use of natural gas as the primary fuel with a maximum sulfur content of 1 grain S/100 scf and the limited use of distillate oil with a maximum sulfur content of 0.05% by weight. Pursuant NSPS Subpart KKKK provisions in 40 CFR 60, the maximum sulfur content of any fuel fired in the combustion turbine shall not exceed 0.06 lb SO<sub>2</sub>/MMBtu. This data shall be submitted with the annual operating report.
- i. There is no standard for VOC emissions. *{Permitting Note: Based on vendor data and installation of the oxidation catalyst, estimated maximum VOC emissions are less than 40 tons per year for the project to avoid PSD preconstruction review.}*
- j. Compliance with the opacity standard shall be determined by EPA Method 9 observations. [Rule 62-212.400(BACT), F.A.C.]
- k. The "Equivalent Emissions @ 59°F" are the total emissions from Units 1 and 2. Estimated annual emissions are *for informational purposes only* and are based on the most stringent emissions rate when the CT is firing natural gas for 8,520 hours/year, the emissions while firing DFO for 240 hours/year and DB emissions firing only natural gas for approximately 5,833 hours/year.

[NSPS 40 CFR 60, Subpart KKKK; Requirements of BACT dated November 20, 1991 issued with original Permit No. AC35-196459 (PSD-FL-176) and subsequent modifications thereto as re-established herein]

11. Excess Emissions: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing: best operational practices to minimize emissions are adhered to; and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period. Rule 62-210.700(Excess Emissions), F.A.C., cannot vary or supersede any federal NSPS or NESHAP provision. [Rule 62-210.700(5), F.A.C.]

#### TESTING REQUIREMENTS

12. Test Methods: As required, tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content <i>{Note: These methods shall be used to support the CO test.}</i>
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources <i>{Note: The method shall be based on a continuous sampling train.}</i>

The above methods are described in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.401, F.A.C.; and Appendix A of 40 CFR 60]



---

### SECTION III. SPECIFIC CONDITIONS FOR EMISSIONS UNITS

---

#### Subsection A. Combined Cycle Units

13. **Test Notifications:** At least 15 days prior to the date on which each formal compliance test is to begin, the permittee shall notify the Compliance Authority 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.]
14. **Initial Compliance Tests:** Each combustion turbine shall demonstrate compliance with the CO and opacity standards on each authorized fuel by conducting initial tests within 60 days of achieving permitted capacity, but not later than 180 days after first fire. Compliance with the NO<sub>x</sub> standards shall be demonstrated by the required CEMS. *{Permitting Note: The requirement to conduct initial compliance stack testing for the existing combustion turbines has been satisfied.}* [Rule 62-297.310(7)(a)1, F.A.C.]
15. **Annual Compliance Tests:** During each federal fiscal year (October 1<sup>st</sup> – September 30<sup>th</sup>), each combustion turbine shall demonstrate compliance with the CO and opacity standards for natural gas by conducting annual tests. Any combustion turbine that does not operate for more than 400 hours per year shall only conduct a CO and visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit. [Rule 62-297.310(7)(a)4 and 8, F.A.C.]
16. **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.]

#### MONITORING REQUIREMENTS

17. **NO<sub>x</sub> CEMS:** The permittee shall install, certify, calibrate, operate and maintain a CEMS to demonstrate compliance with the NO<sub>x</sub> standards. The permittee shall comply with the applicable requirements in Appendix E (CEMS Requirements) of this permit.  
[Rules 62-212.400(BACT) and 62-296.470(CAIR); and NSPS, Subpart KKKK]
18. **Water Injection System:** The permittee shall install, calibrate, operate and maintain a monitor to continuously measure and record the ratio of water or steam to fuel being fired in the combustion turbine. This monitoring data shall be used as a backup to demonstrate compliance with the NO<sub>x</sub> standards if the NO<sub>x</sub> CEMS is not available. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]
19. **Fuel Consumption:** The permittee shall install, calibrate, operate and maintain fuel monitoring equipment for each unit sufficient to demonstrate: that actual operation is within the specified permitted capacity, compliance with the restrictions on fuel consumption and actual annual fuel consumption for the Annual Operating Report. The permittee shall record the consumption of each fuel used for the given time period.  
[Rule 62-4.070(3), F.A.C.]
20. **Fuel Sulfur Monitoring:**
  - a. **Natural Gas:** For each month, the permittee shall obtain the representative fuel sulfur concentration in the pipeline-quality natural gas as determined by the pipeline vendor or by fuel analysis. The permittee shall calculate and record the 12-month rolling average of the natural gas sulfur content.
  - b. **Distillate Oil:** For each delivery, the permittee shall obtain a fuel vendor certification of the fuel sulfur content prior to combining it with fuel oil already in the existing storage tank. Otherwise, the permittee shall have a sample of the distillate oil (as delivered) analyzed for the sulfur content.  
[Rule 62-4.070(3), F.A.C. and NSPS Subpart KKKK]

### SECTION III. SPECIFIC CONDITIONS FOR EMISSIONS UNITS

---

#### Subsection A. Combined Cycle Units

##### RECORDS AND REPORTS

21. Stack Test Report: Within 45 days after the last sampling run of each test is completed, the permittee shall submit a test report to the Compliance Authority on the results of each such test in accordance with Rule 62-297.310(8), F.A.C. as shown in Appendix D of this permit. The following information shall also be included with each test report: the NO<sub>x</sub> emissions for each test run as determined by CEMS; the average water-to-fuel ratio for each test run; the fuel consumption and heat input rates of the CT and DB for each test run; and a summary of any maintenance conducted on or evaluation (reactivity) performed for the oxidation catalyst system. [Rule 62-4.070(3), F.A.C.]
22. Fuel Sulfur Records: The permittee shall demonstrate compliance with the sulfur limit for natural gas by: keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied for each month of operation. These records will be used to determine the 12-month rolling average of the natural gas sulfur content. The permittee shall demonstrate compliance with the distillate oil sulfur limit by maintaining records of the fuel vendor certification or actual analysis of the fuel sulfur content for each delivery. [Rule 62-4.070(3), F.A.C. and NSPS Subpart KKKK]

##### NSPS PROVISIONS

23. Combined Cycle Combustion Turbines: Each combined cycle combustion turbine and duct burner system is subject to the applicable requirements in NSPS Subparts A (General Provisions) and KKKK (Stationary Combustion Turbines) of 40 CFR 60. See Appendix F.  
[Rule 62-204.800, F.A.C. and 40 CFR 60, Subpart A and KKKK]

## **SECTION 4. APPENDICES (DRAFT)**

---

### **Contents**

- Appendix A. Citation Formats and Glossary of Common Terms
- Appendix B. General Conditions
- Appendix C. Common Conditions
- Appendix D. Common Testing Requirements
- Appendix E. CEMS Requirements
- Appendix F. NSPS, Subpart A – General Provisions
- Appendix G. NSPS, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
- Appendix H. Heat Input vs. CT Inlet Temperature Curve

**CITATION FORMATS**

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

**Old Permit Numbers**

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

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

**New Permit Numbers**

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

Where: “099” represents the specific county ID number in which the project is located  
“2222” represents the specific facility ID number for that county  
“001” identifies the specific permit project number  
“AC” identifies the permit as an air construction permit  
“AF” identifies the permit as a minor source federally enforceable state operation permit  
“AO” identifies the permit as a minor source air operation permit  
“AV” identifies the permit as a major Title V air operation permit

**PSD Permit Numbers**

Example: Permit No. PSD-FL-317

Where: “PSD” means issued pursuant to the preconstruction review requirements of the Prevention of Significant Deterioration of Air Quality  
“FL” means that the permit was issued by the State of Florida  
“317” identifies the specific permit project number

**Florida Administrative Code (F.A.C.)**

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

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

**Code of Federal Regulations (CFR)**

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

**GLOSSARY OF COMMON TERMS**

° F: degrees Fahrenheit

µg: microgram

AAQS: Ambient Air Quality Standard

acf: actual cubic feet

acfm: actual cubic feet per minute

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

**BACT:** best available control technology

**bhp:** brake horsepower

**Btu:** British thermal units

**CAM:** compliance assurance monitoring

**CEMS:** continuous emissions monitoring system

**cfm:** cubic feet per minute

**CFR:** Code of Federal Regulations

## SECTION 4. APPENDIX A (DRAFT)

### Citation Formats and Glossary of Common Terms

<b>CAA:</b> Clean Air Act	<b>NESHAP:</b> National Emissions Standards for Hazardous Air Pollutants
<b>CMS:</b> continuous monitoring system	<b>NO<sub>x</sub>:</b> nitrogen oxides
<b>CO:</b> carbon monoxide	<b>NSPS:</b> New Source Performance Standards
<b>CO<sub>2</sub>:</b> carbon dioxide	<b>O&amp;M:</b> operation and maintenance
<b>COMS:</b> continuous opacity monitoring system	<b>O<sub>2</sub>:</b> oxygen
<b>DARM:</b> Division of Air Resource Management	<b>Pb:</b> lead
<b>DEP:</b> Department of Environmental Protection	<b>PM:</b> particulate matter
<b>Department:</b> Department of Environmental Protection	<b>PM<sub>10</sub>:</b> particulate matter with a mean aerodynamic diameter of 10 microns or less
<b>dscf:</b> dry standard cubic feet	<b>ppm:</b> parts per million
<b>dscfm:</b> dry standard cubic feet per minute	<b>ppmv:</b> parts per million by volume
<b>EPA:</b> Environmental Protection Agency	<b>ppmvd:</b> parts per million by volume, dry basis
<b>ESP:</b> electrostatic precipitator (control system for reducing particulate matter)	<b>QA:</b> quality assurance
<b>EU:</b> emissions unit	<b>QC:</b> quality control
<b>F:</b> fluoride	<b>PSD:</b> prevention of significant deterioration
<b>F.A.C.:</b> Florida Administrative Code	<b>psi:</b> pounds per square inch
<b>F.A.W.:</b> Florida Administrative Weekly	<b>PTE:</b> potential to emit
<b>F.D.:</b> forced draft	<b>RACT:</b> reasonably available control technology
<b>F.S.:</b> Florida Statutes	<b>RATA:</b> relative accuracy test audit
<b>FGD:</b> flue gas desulfurization	<b>RBLC:</b> EPA's RACT/BACT/LAER Clearinghouse
<b>FGR:</b> flue gas recirculation	<b>SAM:</b> sulfuric acid mist
<b>ft<sup>2</sup>:</b> square feet	<b>scf:</b> standard cubic feet
<b>ft<sup>3</sup>:</b> cubic feet	<b>scfm:</b> standard cubic feet per minute
<b>gpm:</b> gallons per minute	<b>SIC:</b> standard industrial classification code
<b>gr:</b> grains	<b>SIP:</b> State Implementation Plan
<b>HAP:</b> hazardous air pollutant	<b>SNCR:</b> selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)
<b>Hg:</b> mercury	<b>SO<sub>2</sub>:</b> sulfur dioxide
<b>I.D.:</b> induced draft	<b>TPD:</b> tons/day
<b>ID:</b> identification	<b>TPH:</b> tons per hour
<b>kPa:</b> kilopascals	<b>TPY:</b> tons per year
<b>lb:</b> pound	<b>TRS:</b> total reduced sulfur
<b>MACT:</b> maximum achievable technology	<b>UTM:</b> Universal Transverse Mercator coordinate system
<b>MMBtu:</b> million British thermal units	<b>VE:</b> visible emissions
<b>MSDS:</b> material safety data sheets	<b>VOC:</b> volatile organic compounds
<b>MW:</b> megawatt	

---

**SECTION 4. APPENDIX B (DRAFT)****General Conditions**

---

The permittee shall comply with the following general conditions from Rule 624.160, F.A.C.

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit, are “permitconditions” and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in subsections 403.987(6) and 403.722(5), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other department permit that may be required for other aspects of the total project which are not addressed in this permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and 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 and 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 reasonable times, access to the premises where the permitted activity is located or conducted to:
  - a. Have access to and copy any records that must be kept under 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 noncompliance; and
  - b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time then noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance. 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 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

**General Conditions**

---

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. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard.
11. This permit is transferable only upon Department approval in accordance with Rules 62-4120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
  - a. Determination of Best Available Control Technology (not applicable to this project);
  - b. Determination of Prevention of Significant Deterioration (applies to original project); and
  - c. Compliance with New Source Performance Standards (Subparts A and KKKK in 40 CFR 60).
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 for 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:
    - (a) The date, exact place, and time of sampling or measurements;
    - (b) The person responsible for performing the sampling or measurements;
    - (c) The dates analyses were performed;
    - (d) The person responsible for performing the analyses;
    - (e) The analytical techniques or methods used;
    - (f) 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.

---

## SECTION 4. APPENDIX C (DRAFT)

### Common Conditions

---

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

#### EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 624.130, 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 2 hours in any 24-hour period unless specifically authorized by the Department for longer duration. Pursuant to Rule 62-210.700(5), F.A.C., the permit subsection may specify more or less stringent requirements for periods of excess emissions. Rule 62-210-700(Excess Emissions), F.A.C., cannot vary or supersede any federal NSPS or NESHAP provision. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(Definitions), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

#### RECORDS AND REPORTS

10. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]
11. Emissions Computation and Reporting
  - a. Applicability. This rule sets forth required methodologies to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance



## SECTION 4. APPENDIX C (DRAFT)

### Common Conditions

with this rule. This rule is not intended to establish methodologies for determining compliance with the emission limitations of any air permit. [Rule 62-210.370(1), F.A.C.]

- b. *Computation of Emissions.* For any of the purposes set forth in subsection 62-210.370(1), F.A.C., the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.
- (1) *Basic Approach.* The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.
- (a) If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.
- (b) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.
- (c) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.
- (2) *Continuous Emissions Monitoring System (CEMS).*
- (a) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:
- 1) The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or
- 2) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.
- (b) Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:
- 1) A calibrated flow meter that records data on a continuous basis, if available; or
- 2) The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.
- (c) The owner or operator may use CEMS data in combination with an appropriate factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.
- (3) *Mass Balance Calculations.*
- (a) An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:
- 1) Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and

## Common Conditions

- 2) Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the process or in the capture and destruction of the pollutant by the unit's air pollution control equipment.
  - (b) Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.
  - (c) In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.
- (4) Emission Factors.
- a. An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.
    - 1) If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.
    - 2) Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed
    - 3) The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.
  - b. If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.
- (5) Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.
- (6) Accounting for Emissions During Periods of Startup and Shutdown. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.
- (7) Fugitive Emissions. In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or emissions unit.
- (8) Recordkeeping. The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

[Rule 62-210.370(2), F.A.C.]

c. *Annual Operating Report for Air Pollutant Emitting Facility*

- (1) The Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for the following facilities:
  - a. All Title V sources.
  - b. All synthetic non-Title V sources.
  - c. All facilities with the potential to emit ten (10) tons per year or more of volatile organic compounds or twenty-five (25) tons per year or more of nitrogen oxides and located in an ozone nonattainment area or ozone air quality maintenance area.
  - d. All facilities for which an annual operating report is required by rule or permit.
- (2) Notwithstanding paragraph 62-210.370(3)(a), F.A.C., no annual operating report shall be required for any facility operating under an air general permit.
- (3) The annual operating report shall be submitted to the appropriate Department of Environmental Protection (DEP) division, district or DEP-approved local air pollution control program office by April 1 of the following year. If the report is submitted using the Department's electronic annual operating report software, there is no requirement to submit a copy to any DEP or local air program office.
- (4) Emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C., for purposes of the annual operating report.
- (5) Facility Relocation. Unless otherwise provided by rule or more stringent permit condition, the owner or operator of a relocatable facility must submit a Facility Relocation Notification Form (DEP Form No. 62-210.900(6)) to the Department at least 30 days prior to the relocation. A separate form shall be submitted for each facility in the case of the relocation of multiple facilities which are jointly owned or operated.

[Rule 62-210.370(3), F.A.C.]

---

**SECTION 4. APPENDIX D (DRAFT)****Common Testing Requirements**

---

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

**COMPLIANCE TESTING REQUIREMENTS**

1. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]
2. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]
3. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
4. Applicable Test Procedures:
  - a. Required Sampling Time.
    - (1) Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
    - (2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
      - (a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
      - (b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.
      - (c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
  - b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

## SECTION 4. APPENDIX D (DRAFT)

### Common Testing Requirements

- c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.
- d. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.
- e. Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

TABLE 297.310-1 CALIBRATION SCHEDULE			
ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calibration liquid in glass	5° F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5° F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/- 0.001" mean of at least three readings; Max. deviation between readings, 0.004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, when 5% change observed, annually	Spirometer or calibrated wet test or dry gas test meter	2%
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

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

#### 5. Determination of Process Variables:

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

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

---

**SECTION 4. APPENDIX D (DRAFT)****Common Testing Requirements**

---

6. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.
- a. Permanent Test Facilities. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.
  - b. Temporary Test Facilities. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.
  - c. Sampling Ports.
    - (1) All sampling ports shall have a minimum inside diameter of 3 inches.
    - (2) The ports shall be capable of being sealed when not in use.
    - (3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.
    - (4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.
    - (5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.
  - d. Work Platforms.
    - (1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.
    - (2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.
    - (3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.
    - (4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.
  - e. Access to Work Platform.
    - (1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.
    - (2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.
  - f. Electrical Power.

## SECTION 4. APPENDIX D (DRAFT)

### Common Testing Requirements

- (1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.
- (2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. Sampling Equipment Support.

- (1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.
  - (a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.
  - (b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.
  - (c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.
- (2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.
- (3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

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

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

a. General Compliance Testing.

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.
2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
  - (a) Did not operate; or
  - (b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,
4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

## SECTION 4. APPENDIX D (DRAFT)

### Common Testing Requirements

- (a) Visible emissions, if there is an applicable standard;
  - (b) Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
  - (c) Each NESHAP pollutant, if there is an applicable emission standard.
- 5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
  - 6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.
  - 7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.
  - 8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
  - 9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
  - 10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.
    - (a) 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.
    - (b) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of paragraph 62-297.310(7)(b), F.A.C., shall apply.

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

### REPORTS

#### 8. Test Reports:

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



---

**SECTION 4. APPENDIX D (DRAFT)****Common Testing Requirements**

---

- c. 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.]

**MISCELLANEOUS**

9. Stack and Duct: The terms stack and duct are used interchangeably in this rule. [Rule 62-297.310(9), F.A.C.]

---

## SECTION 4. APPENDIX E (DRAFT)

### Continuous Emission Monitoring System (CEMS) Requirements

---

#### CEMS OPERATION PLAN

1. Affected Units: The permittee is required to install and operate a NO<sub>x</sub> CEMS on each of the two combined cycle gas turbines (EU-003 and EU-004).
2. CEMS Operation Plan: The owner or operator shall maintain a facility-wide plan for the proper installation, calibration, maintenance and operation of each NO<sub>x</sub> CEMS required by this permit. Copies of this plan shall be provided to the Compliance Authority and kept on site for review. The owner or operator shall revise this plan as necessary and provide updates to the Compliance Authority.

#### INSTALLATION, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

3. Installation Deadline: The owner or operator shall install and operate a NO<sub>x</sub> CEMS in accordance with the provisions of 40 CFR 75 and NSPS Subparts A and KKKK in 40 CFR 60. For this project, each NO<sub>x</sub> CEMS has already been installed and certified.
4. Installation: All CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The owner or operator shall locate the CEMS by following the procedures contained in the applicable performance specification of 40 CFR Part 60, Appendix B.
5. Span Values and Dual Range Monitors: The owner or operator shall set appropriate span values for the CEMS. The owner or operator shall install dual range monitors if required by and in accordance with the CEMS Operation Plan.
6. Continuous Flow Monitor: For compliance with mass emission rate standards, the owner or operator shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to 40 FR Part 60, Appendix B, Performance Specification 6. Alternatively, the owner or operator may install a fuel flow monitor and use an appropriate F-Factor computational approach to calculate stack exhaust flow rate.
7. Diluent Monitor: If it is necessary to correct the CEMS output to the oxygen concentrations specified in this permit's emission standards, the owner or operator shall either install an oxygen monitor or install a CO<sub>2</sub> monitor and use an appropriate F-Factor computational approach.
8. Moisture Correction: If necessary, the owner or operator shall 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).  
*{Permitting Note: The CEMS Operation Plan will contain additional CEMS-specific details and procedures for installation.}*
9. Performance Specifications: The owner or operator shall evaluate the acceptability of each CEMS by conducting the appropriate performance specification, as follows. CEMS determined to be unacceptable shall not be considered installed for purposes of meeting the timelines of this permit. For NO<sub>x</sub> monitors, the owner or operator shall conduct Performance Specification 2 of 40 CFR Part 60, Appendix B.
10. Quality Assurance: The owner or operator shall follow the quality assurance procedures of 40 CFR Part 60, Appendix F. The required RATA tests for NO<sub>x</sub> shall be performed using EPA Method 7E in Appendix A of 40 CFR Part 60. NO<sub>x</sub> emissions shall be expressed "as NO<sub>2</sub>."
11. Substituting RATA Tests for Compliance Tests: Data collected during CEMS quality assurance RATA tests can substitute for annual stack tests, and vice versa, at the option of the owner or operator, provided the owner or operator indicates this intent in the submitted test protocol and follows the procedures outlined in the CEMS Operation Plan.

**CALCULATION APPROACH**

12. CEMS Used for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the owner or operator shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit.
13. CEMS Data: Each CEMS shall monitor and record emissions during all periods of operation and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments and span adjustments, and except for allowable data exclusions as per Condition 19 of this Appendix.
14. Operating Hours and Operating Days: For purposes of this Appendix, the following definitions shall apply. An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Unless otherwise specified by this permit, any day with at least one operating hour for an emissions unit is an operating day for that emission unit.
15. Valid Hourly Averages: Each CEMS shall be designed and operated to sample, analyze and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.
  - a. Hours that are not operating hours are not valid hours.
  - b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."
16. Compliance Averages: Compliance with the "24-hour block average" shall be determined for each calendar day of operation by calculating the arithmetic average of valid hourly averages collected during the calendar day.

**MONITOR AVAILABILITY**

17. Monitor Availability: The quarterly excess emissions report shall identify monitor availability for each quarter in which the unit operated. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter in which the unit operated for more than 760 hours. 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.

**EXCESS EMISSIONS**

18. 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* means the cessation of the operation of an emissions unit for any purpose.
  - c. *Malfunction* means any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual

manner.

19. 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.
20. Data Exclusion Procedures for SIP Compliance: As per the procedures in this condition, limited amounts of CEMS emissions data may be excluded from the corresponding compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. The data exclusion procedures of this condition apply only to SIP-based emission limits.
  - a. *Excess Emissions*. Data in excess of the applicable emission standard may be excluded from compliance calculations if the data are collected during periods of permitted excess emissions (for example, during startup, shutdown or malfunction). The maximum duration of excluded data is 2 hours in any 24-hour period, unless some other duration is specified by this permit.
  - b. *Limited Data Exclusion*. If the compliance calculation using all valid CEMS emission data, as defined in Condition 14 of this Appendix, indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.
  - c. *Event Driven Exclusion*. The underlying event (for example, the startup, shutdown or malfunction event) must precede the data exclusion. If there is no underlying event, then no data may be excluded. Only data collected during the event may be excluded.
  - d. *Reporting Excluded Data*. The data exclusion procedures of this condition are not necessarily the same procedures used for excess emissions as defined by federal rules. Quarterly or semi-annual reports required by this permit shall indicate not only the duration of data excluded from SIP compliance calculations but also the number of excess emissions as defined by federal rules.
21. Notification Requirements: The owner or operator shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate noncompliance 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. For malfunctions, notification is sufficient for the owner or operator to exclude CEMS data.

## ANNUAL EMISSIONS

22. CEMS Used for Calculating Annual Emissions: All valid data, as defined in Condition 14 of this Appendix, shall be used when calculating annual emissions.
  - a. Annual emissions shall include data collected during startup, shutdown and malfunction periods.
  - b. Annual emissions shall include data collected during periods when the emission unit is not operating but emissions are being generated (for example, when firing fuel to warm up a process for some period of time prior to the emission unit's startup).
  - c. Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit or RAA. These periods of time shall be considered missing data for purposes of calculating annual emissions.
  - d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered missing data for purposes of calculating annual emissions.

## SECTION 4. APPENDIX E (DRAFT)

### Continuous Emission Monitoring System (CEMS) Requirements

---

23. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average. For each hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the owner or operator shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hour block average.
24. Emissions Calculation: Hourly emissions shall be calculated for each hour as the product of the 1-hour block average and the duration of pollutant emissions during that hour. Annual emissions shall be calculated as the sum of all hourly emissions occurring during the year.

---

## SECTION 4. APPENDIX F (DRAFT)

### NSPS, Subpart A - General Provisions

---

In accordance with Rule 62-204.800, F.A.C., the following federal regulation in Title 40 of the Code of Federal Regulations (CFR) was adopted by reference. The original federal rule numbering has been retained.

*Federal Revision Date: January 28, 2009*

*State Rule Effective Date: November 18, 2009*

*Standardized Conditions Revision Date: February 5, 2010*

#### **Subpart A—General Provisions**

##### **§ 60.1 Applicability.**

- (a) Except as provided in subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
- (b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
- (c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (Act) as amended November 15, 1990 (42 U.S.C. 7661). For more information about obtaining an operating permit see part 70 of this chapter.
- (d) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia. {Not Applicable}*

[40 FR 53346, Nov. 17, 1975, as amended at 55 FR 51382, Dec. 13, 1990; 59 FR 12427, Mar. 16, 1994; 62 FR 52641, Oct. 8, 1997]

##### **§ 60.2 Definitions.**

The terms used in this part are defined in the Act or in this section as follows:

*Act* means the Clean Air Act (42 U.S.C. 7401 *et seq.* )

*Administrator* means the Administrator of the Environmental Protection Agency or his authorized representative.

*Affected facility* means, with reference to a stationary source, any apparatus to which a standard is applicable.

*Alternative method* means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.

*Approved permit program* means a State permit program approved by the Administrator as meeting the requirements of part 70 of this chapter or a Federal permit program established in this chapter pursuant to Title V of the Act (42 U.S.C. 7661).

*Capital expenditure* means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable "annual asset guideline repair allowance percentage" specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any "excluded additions" as defined in IRS Publication 534, as would be done for tax purposes.

**SECTION 4. APPENDIX F (DRAFT)**  
**NSPS, Subpart A - General Provisions**

---

*Clean coal technology demonstration project* means a project using funds appropriated under the heading 'Department of Energy-Clean Coal Technology', up to a total amount of \$2,500,000,000 for commercial demonstrations of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency.

*Commenced* means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

*Construction* means fabrication, erection, or installation of an affected facility.

*Continuous monitoring system* means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.

*Electric utility steam generating unit* means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

*Equivalent method* means any method of sampling and analyzing for an air pollutant which has been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.

*Excess Emissions and Monitoring Systems Performance Report* is a report that must be submitted periodically by a source in order to provide data on its compliance with stated emission limits and operating parameters, and on the performance of its monitoring systems.

*Existing facility* means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.

*Force majeure* means, for purposes of §60.8, an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents the owner or operator from complying with the regulatory requirement to conduct performance tests within the specified timeframe despite the affected facility's best efforts to fulfill the obligation. Examples of such events are acts of nature, acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility.

*Isokinetic sampling* means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

*Issuance* of a part 70 permit will occur, if the State is the permitting authority, in accordance with the requirements of part 70 of this chapter and the applicable, approved State permit program. When the EPA is the permitting authority, issuance of a Title V permit occurs immediately after the EPA takes final action on the final permit.

*Malfunction* means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

*Modification* means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that

facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

*Monitoring device* means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.

*Nitrogen oxides* means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

*One-hour period* means any 60-minute period commencing on the hour.

*Opacity* means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

*Owner or operator* means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

*Part 70 permit* means any permit issued, renewed, or revised pursuant to part 70 of this chapter.

*Particulate matter* means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

*Permit program* means a comprehensive State operating permit system established pursuant to title V of the Act (42 U.S.C. 7661) and regulations codified in part 70 of this chapter and applicable State regulations, or a comprehensive Federal operating permit system established pursuant to title V of the Act and regulations codified in this chapter.

*Permitting authority* means:

- (1) The State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to carry out a permit program under part 70 of this chapter; or
- (2) The Administrator, in the case of EPA-implemented permit programs under title V of the Act (42 U.S.C. 7661).

*Proportional sampling* means sampling at a rate that produces a constant ratio of sampling rate to stack gas flow rate.

*Reactivation of a very clean coal-fired electric utility steam generating unit* means any physical change or change in the method of operation associated with the commencement of commercial operations by a coal-fired utility unit after a period of discontinued operation where the unit:

- (1) Has not been in operation for the two-year period prior to the enactment of the Clean Air Act Amendments of 1990, and the emissions from such unit continue to be carried in the permitting authority's emissions inventory at the time of enactment;
- (2) Was equipped prior to shut-down with a continuous system of emissions control that achieves a removal efficiency for sulfur dioxide of no less than 85 percent and a removal efficiency for particulates of no less than 98 percent;
- (3) Is equipped with low-NO<sub>x</sub> burners prior to the time of commencement of operations following reactivation; and
- (4) Is otherwise in compliance with the requirements of the Clean Air Act.

*Reference method* means any method of sampling and analyzing for an air pollutant as specified in the applicable subpart.



**SECTION 4. APPENDIX F (DRAFT)**  
**NSPS, Subpart A - General Provisions**

---

*Repowering* means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990. Repowering shall also include any oil and/or gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

*Run* means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

*Shutdown* means the cessation of operation of an affected facility for any purpose.

*Six-minute period* means any one of the 10 equal parts of a one-hour period.

*Standard* means a standard of performance proposed or promulgated under this part.

*Standard conditions* means a temperature of 293 K (68F) and a pressure of 101.3 kilopascals (29.92 in Hg).

*Startup* means the setting in operation of an affected facility for any purpose.

*State* means all non-Federal authorities, including local agencies, interstate associations, and State-wide programs, that have delegated authority to implement: (1) The provisions of this part; and/or (2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context.

*Stationary source* means any building, structure, facility, or installation which emits or may emit any air pollutant.

*Title V permit* means any permit issued, renewed, or revised pursuant to Federal or State regulations established to implement title V of the Act (42 U.S.C. 7661). A title V permit issued by a State permitting authority is called a part 70 permit in this part.

*Volatile Organic Compound* means any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an equivalent method, an alternative method, or which is determined by procedures specified under any subpart.

[44 FR 55173, Sept. 25, 1979, as amended at 45 FR 5617, Jan. 23, 1980; 45 FR 85415, Dec. 24, 1980; 54 FR 6662, Feb. 14, 1989; 55 FR 51382, Dec. 13, 1990; 57 FR 32338, July 21, 1992; 59 FR 12427, Mar. 16, 1994; 72 FR 27442, May 16, 2007]

### **§ 60.3 Units and abbreviations.**

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) System International (SI) units of measure:

A—ampere

g—gram

Hz—hertz

J—joule

K—degree Kelvin

**SECTION 4. APPENDIX F (DRAFT)**  
**NSPS, Subpart A - General Provisions**

---

kg—kilogram

m—meter

m<sup>3</sup>—cubic meter

mg—milligram—10<sup>-3</sup> gram

mm—millimeter—10<sup>-3</sup> meter

Mg—megagram—10<sup>6</sup> gram

mol—mole

N—newton

ng—nanogram—10<sup>-9</sup> gram

nm—nanometer—10<sup>-9</sup> meter

Pa—pascal

s—second

V—volt

W—watt

Ω—ohm

μg—microgram—10<sup>-6</sup> gram

(b) Other units of measure:

Btu—British thermal unit

°C—degree Celsius (centigrade)

cal—calorie

cfm—cubic feet per minute

cu ft—cubic feet

dcf—dry cubic feet

dcm—dry cubic meter

dscf—dry cubic feet at standard conditions

dscm—dry cubic meter at standard conditions

eq—equivalent

°F—degree Fahrenheit

ft—feet

gal—gallon

gr—grain

g-eq—gram equivalent

hr—hour

in—inch

k—1,000

l—liter

lpm—liter per minute

lb—pound

meq—milliequivalent

min—minute

ml—milliliter

mol. wt.—molecular weight

ppb—parts per billion

ppm—parts per million

psia—pounds per square inch absolute

psig—pounds per square inch gage

°R—degree Rankine

scf—cubic feet at standard conditions

scfh—cubic feet per hour at standard conditions

scm—cubic meter at standard conditions

sec—second

sq ft—square feet

std—at standard conditions

(c) Chemical nomenclature:

CdS—cadmium sulfide

CO—carbon monoxide

CO<sub>2</sub>—carbon dioxide

HCl—hydrochloric acid

Hg—mercury

H<sub>2</sub>O—water

H<sub>2</sub>S—hydrogen sulfide

H<sub>2</sub>SO<sub>4</sub>—sulfuric acid

N<sub>2</sub>—nitrogen

NO—nitric oxide

NO<sub>2</sub>—nitrogen dioxide

NO<sub>x</sub>—nitrogen oxides

O<sub>2</sub>—oxygen

SO<sub>2</sub>—sulfur dioxide

SO<sub>3</sub>—sulfur trioxide

SO<sub>x</sub>—sulfur oxides

(d) Miscellaneous:

A.S.T.M.—American Society for Testing and Materials

[42 FR 37000, July 19, 1977; 42 FR 38178, July 27, 1977]

#### § 60.4 Address.

All addresses that pertain to Florida have been incorporated. To see the complete list of addresses please go to <http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&rgn=div6&view=text&node=40:6.0.1.1.1.1&idno=40>.

Link to an amendment published at 73 FR 18164, Apr. 3, 2008.

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the appropriate Regional Office of the U.S. Environmental Protection Agency to the attention of the Director of the Division indicated in the following list of EPA Regional Offices.

Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee),  
Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 345 Courtland Street,  
NE., Atlanta, GA 30365.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(K) Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office  
Building, 2600 Blair Stone Road, Tallahassee, FL 32301.

[40 FR 18169, Apr. 25, 1975]

**Editorial Note:** For Federal Register citations affecting §60.4 see the List of CFR Sections Affected which appears in the Finding Aids section of the printed volume and on GPO Access.

#### § 60.5 Determination of construction or modification.

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

[40 FR 58418, Dec. 16, 1975]

#### § 60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b)

(1) A separate request shall be submitted for each construction or modification project.

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974]

**§ 60.7 Notification and record keeping.**

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(1) A notification of the date construction (or reconstruction as defined under §60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

(2) [Reserved]

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in §60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with §60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by §60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by §60.8 in lieu of Method 9 observation data as allowed by §60.11(e)(5) of this part. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

**SECTION 4. APPENDIX F (DRAFT)**  
**NSPS, Subpart A - General Provisions**

(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) need not be submitted unless requested by the Administrator.

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

Figure 1—Summary Report—Gaseous and Opacity Excess Emission and Monitoring System Performance  
Pollutant (Circle One—SO<sub>2</sub>/NO<sub>x</sub>/TRS/H<sub>2</sub>S/CO/Opacity)

Reporting period dates: From \_\_\_\_\_ to \_\_\_\_\_

Company: \_\_\_\_\_

Emission Limitation \_\_\_\_\_

Address: \_\_\_\_\_

Monitor Manufacturer and Model No. \_\_\_\_\_

Date of Latest CMS Certification or Audit \_\_\_\_\_

Process Unit(s) Description: \_\_\_\_\_

Total source operating time in reporting period<sup>1</sup> \_\_\_\_\_

Emission data summary <sup>1</sup>		CMS performance summary <sup>1</sup>	
1. Duration of excess emissions in reporting period due		1. CMS downtime in reporting period due to:	

# SECTION 4. APPENDIX F (DRAFT)

## NSPS, Subpart A - General Provisions

to:			
a. Startup/shutdown		a. Monitor equipment malfunctions	
b. Control equipment problems		b. Non-Monitor equipment malfunctions	
c. Process problems		c. Quality assurance calibration	
d. Other known causes		d. Other known causes	
e. Unknown causes		e. Unknown causes	
2. Total duration of excess emission		2. Total CMS Downtime	
3. Total duration of excess emissions $\times$ (100) [Total source operating time]	% <sup>2</sup>	3. [Total CMS Downtime] $\times$ (100) [Total source operating time]	% <sup>2</sup>

<sup>1</sup>For opacity, record all times in minutes. For gases, record all times in hours.

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

On a separate page, describe any changes since last quarter in CMS, process or controls. I certify that the information contained in this report is true, accurate, and complete.

\_\_\_\_\_  
Name

\_\_\_\_\_  
Signature

\_\_\_\_\_  
Title

\_\_\_\_\_  
Date

(e)

(1) Notwithstanding the frequency of reporting requirements specified in paragraph (c) of this section, an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in paragraph (e)(2) of this section.

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in paragraphs (e)(1) and (e)(2) of this section.

(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.



(g) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

[36 FR 24877, Dec. 28, 1971, as amended at 40 FR 46254, Oct. 6, 1975; 40 FR 58418, Dec. 16, 1975; 45 FR 5617, Jan. 23, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 52 FR 9781, Mar. 26, 1987; 55 FR 51382, Dec. 13, 1990; 59 FR 12428, Mar. 16, 1994; 59 FR 47265, Sep. 15, 1994; 64 FR 7463, Feb. 12, 1999]

#### **§ 60.8 Performance tests.**

(a) Except as specified in paragraphs (a)(1), (a)(2), (a)(3), and (a)(4) of this section, 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 such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(1) If a force majeure is about to occur, occurs, or has occurred for which the affected owner or operator intends to assert a claim of force majeure, the owner or operator shall notify the Administrator, in writing as soon as practicable following the date the owner or operator first knew, or through due diligence should have known that the event may cause or caused a delay in testing beyond the regulatory deadline, but the notification must occur before the performance test deadline unless the initial force majeure or a subsequent force majeure event delays the notice, and in such cases, the notification shall occur as soon as practicable.

(2) The owner or operator shall provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in testing beyond the regulatory deadline to the force majeure; describe the measures taken or to be taken to minimize the delay; and identify a date by which the owner or operator proposes to conduct the performance test. The performance test shall be conducted as soon as practicable after the force majeure occurs.

(3) The decision as to whether or not to grant an extension to the performance test deadline is solely within the discretion of the Administrator. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an extension as soon as practicable.

(4) Until an extension of the performance test deadline has been approved by the Administrator under paragraphs (a)(1), (2), and (3) of this section, the owner or operator of the affected facility remains strictly subject to the requirements of this part.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for

the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the Administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974; 42 FR 57126, Nov. 1, 1977; 44 FR 33612, June 11, 1979; 54 FR 6662, Feb. 14, 1989; 54 FR 21344, May 17, 1989; 64 FR 7463, Feb. 12, 1999; 72 FR 27442, May 16, 2007]

#### **§ 60.9 Availability of information.**

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§60.5 and 60.6 is governed by §§2.201 through 2.213 of this chapter and not by §2.301 of this chapter.)

#### **§ 60.10 State authority.**

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

**§ 60.11 Compliance with standards and maintenance requirements.**

(a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by §60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in paragraph (e)(5) of this section. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e)

(1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in §60.8 unless one of the following conditions apply. If no performance test under §60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under §60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in §60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under §60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in paragraph (e)(5) of this section, the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of this part, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in paragraph (e)(3) of this section, the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with paragraph (b) of this section, shall record the opacity of emissions, and shall report to the Administrator the opacity results along

**SECTION 4. APPENDIX F (DRAFT)**  
**NSPS, Subpart A - General Provisions**

---

with the results of the initial performance test required under §60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in §60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of paragraph (e)(1) of this section shall apply.

(4) An owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by §60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and §60.8 performance test results.

(5) An owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under §60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under §60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under §60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under §60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under §60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in §60.13(c) of this part, that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine compliance with the opacity standard.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by §60.8, the opacity observation results and observer certification required by §60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by §60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with §60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity

standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[38 FR 28565, Oct. 15, 1973, as amended at 39 FR 39873, Nov. 12, 1974; 43 FR 8800, Mar. 3, 1978; 45 FR 23379, Apr. 4, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 51 FR 1790, Jan. 15, 1986; 52 FR 9781, Mar. 26, 1987; 62 FR 8328, Feb. 24, 1997; 65 FR 61749, Oct. 17, 2000]

#### **§ 60.12 Circumvention.**

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[39 FR 9314, Mar. 8, 1974]

#### **§ 60.13 Monitoring requirements.**

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to this part, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under §60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under §60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of this part before the performance test required under §60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under §60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of this part. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under §60.8 and as described in §60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in paragraph (c) of this section at least 10 days before the performance test required under §60.8 is conducted.

---

**SECTION 4. APPENDIX F (DRAFT)****NSPS, Subpart A - General Provisions**

---

(2) Except as provided in paragraph (c)(1) of this section, the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d)

(1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span must, as a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in appendix B of this part. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part, must automatically, intrinsic to the opacity monitor, check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of PS-1 in appendix B of this part. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures must be followed for a COMS. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition using a certified neutral density filter or other related technique to produce a known obstruction of the light beam. Such procedures must provide a system check of all active analyzer internal optics with power or curvature, all active electronic circuitry including the light source and photodetector assembly, and electronic or electro-mechanical systems and hardware and or software used during normal measurement operation.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by paragraph (c) of this section for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by paragraph (c) of this section for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of this part shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple

breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

(h)

(1) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in §60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period.

(2) For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows, except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations:

(i) Except as provided under paragraph (h)(2)(iii) of this section, for a full operating hour (any clock hour with 60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, *i.e.*, one data point in each of the 15-minute quadrants of the hour.

(ii) Except as provided under paragraph (h)(2)(iii) of this section, for a partial operating hour (any clock hour with less than 60 minutes of unit operation), at least one valid data point in each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.

(iii) For any operating hour in which required maintenance or quality-assurance activities are performed:

(A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or

(B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.

(v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.

(vi) Except as provided under paragraph (h)(2)(vii) of this section, data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.

(vii) Owners and operators complying with the requirements of §60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.

(viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (*e.g.* hours with < 30 minutes of unit operation under §60.47b(d)).

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (*e.g.*, ppm pollutant and percent O<sub>2</sub> or ng/J of pollutant).

(3) All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

- (1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.
- (2) Alternative monitoring requirements when the affected facility is infrequently operated.
- (3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.
- (4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.
- (5) Alternative methods of converting pollutant concentration measurements to units of the standards.
- (6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.
- (7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.
- (8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.
- (9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.
- (j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:
  - (1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in Section 8.4 of Performance Specification 2 and substitute the procedures in Section 16.0 if the results of a performance test conducted according to the requirements in §60.8 of this subpart or other tests performed following the criteria in §60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in Section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).
  - (2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure, that the CEMS data indicate that the source emissions are approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as



specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., §60.45(g) (2) and (3), §60.73(e), and §60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in Section 8.4 of Performance Specification 2.

[40 FR 46255, Oct. 6, 1975; 40 FR 59205, Dec. 22, 1975, as amended at 41 FR 35185, Aug. 20, 1976; 48 FR 13326, Mar. 30, 1983; 48 FR 23610, May 25, 1983; 48 FR 32986, July 20, 1983; 52 FR 9782, Mar. 26, 1987; 52 FR 17555, May 11, 1987; 52 FR 21007, June 4, 1987; 64 FR 7463, Feb. 12, 1999; 65 FR 48920, Aug. 10, 2000; 65 FR 61749, Oct. 17, 2000; 66 FR 44980, Aug. 27, 2001; 71 FR 31102, June 1, 2006; 72 FR 32714, June 13, 2007]

**Editorial Note:** At 65 FR 61749, Oct. 17, 2000, §60.13 was amended by revising the words “ng/J of pollutant” to read “ng of pollutant per J of heat input” in the sixth sentence of paragraph (h). However, the amendment could not be incorporated because the words “ng/J of pollutant” do not exist in the sixth sentence of paragraph (h).

#### **§ 60.14 Modification.**

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of “Compilation of Air Pollutant Emission Factors,” EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

---

**SECTION 4. APPENDIX F (DRAFT)****NSPS, Subpart A - General Provisions**

---

- (c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.
- (d) [Reserved]
- (e) The following shall not, by themselves, be considered modifications under this part:
- (1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and §60.15.
  - (2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.
  - (3) An increase in the hours of operation.
  - (4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by §60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.
  - (5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.
  - (6) The relocation or change in ownership of an existing facility.
- (f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.
- (g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.
- (h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.
- (i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.
- (j)
- (1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.
  - (2) This exemption shall not apply to any new unit that:
    - (i) Is designated as a replacement for an existing unit;

(ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and

(iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A *temporary clean coal control technology demonstration project*, for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

[40 FR 58419, Dec. 16, 1975, as amended at 43 FR 34347, Aug. 3, 1978; 45 FR 5617, Jan. 23, 1980; 57 FR 32339, July 21, 1992; 65 FR 61750, Oct. 17, 2000]

#### **§ 60.15 Reconstruction.**

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

- (1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;
- (2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;
- (3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and
- (4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

[40 FR 58420, Dec. 16, 1975]

#### **§ 60.16 Priority list.**

A list of prioritized major source categories may be found at the following EPA web site:

<http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&rgn=div6&view=text&node=40:6.0.1.1.1.1&idno=40>

[47 FR 951, Jan. 8, 1982, as amended at 47 FR 31876, July 23, 1982; 51 FR 42796, Nov. 25, 1986; 52 FR 11428, Apr. 8, 1987; 61 FR 9919, Mar. 12, 1996]

#### **§ 60.17 Incorporations by reference.**

The materials listed below are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of the Federal Register on the date listed. These materials are incorporated as they exist on the date of the approval, and a notice of any change in these materials will be published in the Federal Register. The materials are available for purchase at the corresponding address noted below, and all are available for inspection at the Library (C267-01), U.S. EPA, Research Triangle Park, NC or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030, or go to:

*[http://www.archives.gov/federal\\_register/code\\_of\\_federal\\_regulations/ibr\\_locations.html](http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html)*.

(a) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428-2959; or ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106.

- (1) ASTM A99-76, 82 (Reapproved 1987), Standard Specification for Ferromanganese, incorporation by reference (IBR) approved for §60.261.
- (2) ASTM A100-69, 74, 93, Standard Specification for Ferrosilicon, IBR approved for §60.261.
- (3) ASTM A101-73, 93, Standard Specification for Ferrochromium, IBR approved for §60.261.
- (4) ASTM A482-76, 93, Standard Specification for Ferrochromesilicon, IBR approved for §60.261.
- (5) ASTM A483-64, 74 (Reapproved 1988), Standard Specification for Silicomanganese, IBR approved for §60.261.
- (6) ASTM A495-76, 94, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for §60.261.
- (7) ASTM D86-78, 82, 90, 93, 95, 96, Distillation of Petroleum Products, IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), and 60.633(h).

---

**SECTION 4. APPENDIX F (DRAFT)****NSPS, Subpart A - General Provisions**

---

- (8) ASTM D129–64, 78, 95, 00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§60.106(j)(2), 60.335(b)(10)(i), and Appendix A: Method 19, 12.5.2.2.3.
- (9) ASTM D129–00 (Reapproved 2005), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §60.4415(a)(1)(i).
- (10) ASTM D240–76, 92, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§60.46(c), 60.296(b), and Appendix A: Method 19, Section 12.5.2.2.3.
- (11) ASTM D270–65, 75, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.1.
- (12) ASTM D323–82, 94, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§60.111(l), 60.111a(g), 60.111b(g), and 60.116b(f)(2)(ii).
- (13) ASTM D388–77, 90, 91, 95, 98a, 99 (Reapproved 2004)<sup>e1</sup>, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.24(h)(8), 60.41 of subpart D of this part, 60.45(f)(4)(i), 60.45(f)(4)(ii), 60.45(f)(4)(vi), 60.41Da of subpart Da of this part, 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, and 60.4102.
- (14) ASTM D388–77, 90, 91, 95, 98a, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.251(b) and (c) of subpart Y of this part.
- (15) ASTM D396–78, 89, 90, 92, 96, 98, Standard Specification for Fuel Oils, IBR approved for §§60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, 60.111(b) of subpart K of this part, and 60.111a(b) of subpart Ka of this part.
- (16) ASTM D975–78, 96, 98a, Standard Specification for Diesel Fuel Oils, IBR approved for §§60.111(b) of subpart K of this part and 60.111a(b) of subpart Ka of this part.
- (17) ASTM D1072–80, 90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for §60.335(b)(10)(ii).
- (18) ASTM D1072–90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for §60.4415(a)(1)(ii).
- (19) ASTM D1137–53, 75, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for §60.45(f)(5)(i).
- (20) ASTM D1193–77, 91, Standard Specification for Reagent Water, IBR approved for Appendix A: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.
- (21) ASTM D1266–87, 91, 98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§60.106(j)(2) and 60.335(b)(10)(i).
- (22) ASTM D1266–98 (Reapproved 2003)<sup>e1</sup>, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §60.4415(a)(1)(i).
- (23) ASTM D1475–60 (Reapproved 1980), 90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for §60.435(d)(1), Appendix A: Method 24, Section 6.1; and Method 24A, Sections 6.5 and 7.1.
- (24) ASTM D1552–83, 95, 01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§60.106(j)(2), 60.335(b)(10)(i), and Appendix A: Method 19, Section 12.5.2.2.3.

---

**SECTION 4. APPENDIX F (DRAFT)****NSPS, Subpart A - General Provisions**

---

- (25) ASTM D1552-03, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §60.4415(a)(1)(i).
- (26) ASTM D1826-77, 94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§60.45(f)(5)(ii), 60.46(c)(2), 60.296(b)(3), and Appendix A: Method 19, Section 12.3.2.4.
- (27) ASTM D1835-87, 91, 97, 03a, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§60.41Da of subpart Da of this part, 60.41b of subpart Db of this part, and 60.41c of subpart Dc of this part.
- (28) ASTM D1945-64, 76, 91, 96, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §60.45(f)(5)(i).
- (29) ASTM D1946-77, 90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§60.18(f)(3), 60.45(f)(5)(i), 60.564(f)(1), 60.614(e)(2)(ii), 60.614(e)(4), 60.664(e)(2)(ii), 60.664(e)(4), 60.704(d)(2)(ii), and 60.704(d)(4).
- (30) ASTM D2013-72, 86, Standard Method of Preparing Coal Samples for Analysis, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.
- (31) ASTM D2015-77 (Reapproved 1978), 96, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §60.45(f)(5)(ii), 60.46(c)(2), and Appendix A: Method 19, Section 12.5.2.1.3.
- (32) ASTM D2016-74, 83, Standard Test Methods for Moisture Content of Wood, IBR approved for Appendix A: Method 28, Section 16.1.1.
- (33) ASTM D2234-76, 96, 97b, 98, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for Appendix A: Method 19, Section 12.5.2.1.1.
- (34) ASTM D2369-81, 87, 90, 92, 93, 95, Standard Test Method for Volatile Content of Coatings, IBR approved for Appendix A: Method 24, Section 6.2.
- (35) ASTM D2382-76, 88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§60.18(f)(3), 60.485(g)(6), 60.485a(g)(6), 60.564(f)(3), 60.614(e)(4), 60.664(e)(4), and 60.704(d)(4).
- (36) ASTM D2504-67, 77, 88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§60.485(g)(5) and 60.485a(g)(5).
- (37) ASTM D2584-68 (Reapproved 1985), 94, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for §60.685(c)(3)(i).
- (38) ASTM D2597-94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for §60.335(b)(9)(i).
- (39) ASTM D2622-87, 94, 98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§60.106(j)(2) and 60.335(b)(10)(i).
- (40) ASTM D2622-05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.4415(a)(1)(i).
- (41) ASTM D2879-83, 96, 97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§60.111b(f)(3), 60.116b(e)(3)(ii), 60.116b(f)(2)(i), 60.485(e)(1), and 60.485a(e)(1).

**SECTION 4. APPENDIX F (DRAFT)**  
**NSPS, Subpart A - General Provisions**

---

- (42) ASTM D2880–78, 96, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§60.111(b), 60.111a(b), and 60.335(d).
- (43) ASTM D2908–74, 91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for §60.564(j).
- (44) ASTM D2986–71, 78, 95a, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for Appendix A: Method 5, Section 7.1.1; Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.
- (45) ASTM D3173–73, 87, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.
- (46) ASTM D3176–74, 89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for §60.45(f)(5)(i) and Appendix A: Method 19, Section 12.3.2.3.
- (47) ASTM D3177–75, 89, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.
- (48) ASTM D3178–73 (Reapproved 1979), 89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for §60.45(f)(5)(i).
- (49) ASTM D3246–81, 92, 96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.335(b)(10)(ii).
- (50) ASTM D3246–05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.4415(a)(1)(ii).
- (51) ASTM D3270–73T, 80, 91, 95, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for Appendix A: Method 13A, Section 16.1.
- (52) ASTM D3286–85, 96, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isotherm Bomb Calorimeter, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.
- (53) ASTM D3370–76, 95a, Standard Practices for Sampling Water, IBR approved for §60.564(j).
- (54) ASTM D3792–79, 91, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for Appendix A: Method 24, Section 6.3.
- (55) ASTM D4017–81, 90, 96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for Appendix A: Method 24, Section 6.4.
- (56) ASTM D4057–81, 95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.3.
- (57) ASTM D4057–95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for §60.4415(a)(1).
- (58) ASTM D4084–82, 94, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §60.334(h)(1).
- (59) ASTM D4084–05, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §§60.4360 and 60.4415(a)(1)(ii).
- (60) ASTM D4177–95, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.1.

---

**SECTION 4. APPENDIX F (DRAFT)****NSPS, Subpart A - General Provisions**

---

- (61) ASTM D4177–95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for §60.4415(a)(1).
- (62) ASTM D4239–85, 94, 97, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.
- (63) ASTM D4294–02, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.335(b)(10)(i).
- (64) ASTM D4294–03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.4415(a)(1)(i).
- (65) ASTM D4442–84, 92, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for Appendix A: Method 28, Section 16.1.1.
- (66) ASTM D4444–92, Standard Test Methods for Use and Calibration of Hand-Held Moisture Meters, IBR approved for Appendix A: Method 28, Section 16.1.1.
- (67) ASTM D4457–85 (Reapproved 1991), Test Method for Determination of Dichloromethane and 1, 1, 1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, IBR approved for Appendix A: Method 24, Section 6.5.
- (68) ASTM D4468–85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§60.335(b)(10)(ii) and 60.4415(a)(1)(ii).
- (69) ASTM D4629–02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection, IBR approved for §§60.49b(e) and 60.335(b)(9)(i).
- (70) ASTM D4809–95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §§60.18(f)(3), 60.485(g)(6), 60.485a(g)(6), 60.564(f)(3), 60.614(d)(4), 60.664(e)(4), and 60.704(d)(4).
- (71) ASTM D4810–88 (Reapproved 1999), Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes, IBR approved for §§60.4360 and 60.4415(a)(1)(ii).
- (72) ASTM D5287–97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for §60.4415(a)(1).
- (73) ASTM D5403–93, Standard Test Methods for Volatile Content of Radiation Curable Materials, IBR approved for Appendix A: Method 24, Section 6.6.
- (74) ASTM D5453–00, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for §60.335(b)(10)(i).
- (75) ASTM D5453–05, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for §60.4415(a)(1)(i).
- (76) ASTM D5504–01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§60.334(h)(1) and 60.4360.
- (77) ASTM D5762–02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for §60.335(b)(9)(i).
- (78) ASTM D5865–98, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for §60.45(f)(5)(ii), 60.46(c)(2), and Appendix A: Method 19, Section 12.5.2.1.3.



- (79) ASTM D6216-98, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, IBR approved for Appendix B, Performance Specification 1.
- (80) ASTM D6228-98, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §60.334(h)(1).
- (81) ASTM D6228-98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §§60.4360 and 60.4415.
- (82) ASTM D6348-03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, IBR approved for table 7 of Subpart IIII of this part and table 2 of subpart JJJJ of this part.
- (83) ASTM D6366-99, Standard Test Method for Total Trace Nitrogen and Its Derivatives in Liquid Aromatic Hydrocarbons by Oxidative Combustion and Electrochemical Detection, IBR approved for §60.335(b)(9)(i).
- (84) ASTM D6420-99 (Reapproved 2004) Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, IBR approved for table 2 of subpart JJJJ of this part.
- (85) ASTM D6522-00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for §60.335(a).
- (86) ASTM D6522-00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for table 2 of subpart JJJJ of this part.
- (87) ASTM D6667-01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for §60.335(b)(10)(ii).
- (88) ASTM D6667-04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for §60.4415(a)(1)(ii).
- (89) ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), IBR approved for Appendix B to part 60, Performance Specification 12A, Section 8.6.2.
- (90) ASTM E168-67, 77, 92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), and 60.632(f).
- (91) ASTM E169-63, 77, 93, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), and 60.632(f).
- (92) ASTM E260-73, 91, 96, General Gas Chromatography Procedures, IBR approved for §§60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), and 60.632(f).
- (b) The following material is available for purchase from the Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209.
- (1) AOAC Method 9, Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11-12, IBR approved January 27, 1983 for §§60.204(b)(3), 60.214(b)(3), 60.224(b)(3), 60.234(b)(3).

**SECTION 4. APPENDIX F (DRAFT)**  
**NSPS, Subpart A - General Provisions**

---

- (c) The following material is available for purchase from the American Petroleum Institute, 1220 L Street NW., Washington, DC 20005.
- (1) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February 1980, IBR approved January 27, 1983, for §§60.111(i), 60.111a(f), 60.111a(f)(1) and 60.116b(e)(2)(i).
- (d) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), Dunwoody Park, Atlanta, GA 30341.
- (1) TAPPI Method T624 os-68, IBR approved January 27, 1983 for §60.285(d)(3).
- (e) The following material is available for purchase from the Water Pollution Control Federation (WPCF), 2626 Pennsylvania Avenue NW., Washington, DC 20037.
- (1) Method 209A, Total Residue Dried at 103–105 °C, in Standard Methods for the Examination of Water and Wastewater, 15th Edition, 1980, IBR approved February 25, 1985 for §60.683(b).
- (f) The following material is available for purchase from the following address: Underwriter's Laboratories, Inc. (UL), 333 Pfingsten Road, Northbrook, IL 60062.
- (1) UL 103, Sixth Edition revised as of September 3, 1986, Standard for Chimneys, Factory-built, Residential Type and Building Heating Appliance.
- (g) The following material is available for purchase from the following address: West Coast Lumber Inspection Bureau, 6980 SW. Barnes Road, Portland, OR 97223.
- (1) West Coast Lumber Standard Grading Rules No. 16, pages 5–21 and 90 and 91, September 3, 1970, revised 1984.
- (h) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990.
- (1) ASME QRO–1–1994, Standard for the Qualification and Certification of Resource Recovery Facility Operators, IBR approved for §§60.56a, 60.54b(a), 60.54b(b), 60.1185(a), 60.1185(c)(2), 60.1675(a), and 60.1675(c)(2).
- (2) ASME PTC 4.1–1964 (Reaffirmed 1991), Power Test Codes: Test Code for Steam Generating Units (with 1968 and 1969 Addenda), IBR approved for §§60.46b of subpart Db of this part, 60.58a(h)(6)(ii), 60.58b(i)(6)(ii), 60.1320(a)(3) and 60.1810(a)(3).
- (3) ASME Interim Supplement 19.5 on Instruments and Apparatus: Application, Part II of Fluid Meters, 6th Edition (1971), IBR approved for §§60.58a(h)(6)(ii), 60.58b(i)(6)(ii), 60.1320(a)(4), and 60.1810(a)(4).
- (4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], IBR approved for Tables 1 and 3 of subpart EEEE, Tables 2 and 4 of subpart FFFF, Table 2 of subpart JJJJ, and §§60.4415(a)(2) and 60.4415(a)(3) of subpart KKKK of this part.
- (i) Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication SW–846 Third Edition (November 1986), as amended by Updates I (July 1992), II (September 1994), IIA (August, 1993), IIB (January 1995), and III (December 1996). This document may be obtained from the U.S. EPA, Office of Solid Waste and Emergency Response, Waste Characterization Branch, Washington, DC 20460, and is incorporated by reference for appendix A to part 60, Method 29, Sections 7.5.34; 9.2.1; 9.2.3; 10.2; 10.3; 11.1.1; 11.1.3; 13.2.1; 13.2.2; 13.3.1; and Table 29–3.
- (j) “Standard Methods for the Examination of Water and Wastewater,” 16th edition, 1985. Method 303F: “Determination of Mercury by the Cold Vapor Technique.” This document may be obtained from the American

Public Health Association, 1015 18th Street, NW., Washington, DC 20036, and is incorporated by reference for appendix A to part 60, Method 29, Sections 9.2.3; 10.3; and 11.1.3.

(k) This material is available for purchase from the American Hospital Association (AHA) Service, Inc., Post Office Box 92683, Chicago, Illinois 60675-2683. You may inspect a copy at EPA's Air and Radiation Docket and Information Center (Docket A-91-61, Item IV-J-124), Room M-1500, 1200 Pennsylvania Ave., NW., Washington, DC.

(l) *An Ounce of Prevention: Waste Reduction Strategies for Health Care Facilities.* American Society for Health Care Environmental Services of the American Hospital Association. Chicago, Illinois. 1993. AHA Catalog No. 057007. ISBN 0-87258-673-5. IBR approved for §60.35e and §60.55c.

(l) This material is available for purchase from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161. You may inspect a copy at EPA's Air and Radiation Docket and Information Center (Docket A-91-61, Item IV-J-125), Room M-1500, 1200 Pennsylvania Ave., NW., Washington, DC.

(1) OMB Bulletin No. 93-17: Revised Statistical Definitions for Metropolitan Areas. Office of Management and Budget, June 30, 1993. NTIS No. PB 93-192-664. IBR approved for §60.31e.

(m) This material is available for purchase from at least one of the following addresses: The Gas Processors Association, 6526 East 60th Street, Tulsa, OK, 74145; or Information Handling Services, 15 Inverness Way East, PO Box 1154, Englewood, CO 80150-1154. You may inspect a copy at EPA's Air and Radiation Docket and Information Center, Room B108, 1301 Constitution Ave., NW., Washington, DC 20460.

(1) Gas Processors Association Method 2377-86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, IBR approved for §§60.334(h)(1), 60.4360, and 60.4415(a)(1)(ii).

(2) [Reserved]

(n) This material is available for purchase from IHS Inc., 15 Inverness Way East, Englewood, CO 80112.

(1) International Organization for Standards 8178-4: 1996(E), Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—Part 4: Test Cycles for Different Engine Applications, IBR approved for §60.4241(b).

(2) [Reserved]

[48 FR 3735, Jan. 27, 1983]

**Editorial Note:** For Federal Register citations affecting §60.17, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and on GPO Access.

#### § 60.18 General control device and work practice requirements.

##### (a) *Introduction.*

(1) This section contains requirements for control devices used to comply with applicable subparts of 40 CFR parts 60 and 61. The requirements are placed here for administrative convenience and apply only to facilities covered by subparts referring to this section.

(2) This section also contains requirements for an alternative work practice used to identify leaking equipment. This alternative work practice is placed here for administrative convenience and is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, Appendix A-7, Method 21 monitor.

(b) *Flares.* Paragraphs (c) through (f) apply to flares.

(c)

**SECTION 4. APPENDIX F (DRAFT)**  
**NSPS, Subpart A - General Provisions**

---

- (1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.
- (2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).
- (3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

(i)

(A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity,  $V_{\max}$ , as determined by the following equation:

$$V_{\max} = (X_{H_2} - K_1) * K_2$$

Where:

$V_{\max}$  = Maximum permitted velocity, m/sec.

$K_1$  = Constant, 6.0 volume-percent hydrogen.

$K_2$  = Constant, 3.9(m/sec)/volume-percent hydrogen.

$X_{H_2}$  = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in §60.17).

(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4)

(i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity,  $V_{\max}$ , as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity,  $V_{\max}$ , as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

---

**SECTION 4. APPENDIX F (DRAFT)****NSPS, Subpart A - General Provisions**

---

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f)

(1) Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

(2) 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.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^n C_i H_i$$

[View or download PDF](#)

where:

$H_T$  = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

$$K = \text{Constant}, \frac{1.740 \times 10^{-7}}{\left(\frac{1}{\text{ppm}}\right) \left(\frac{\text{g mole}}{\text{scm}}\right) \left(\frac{\text{MJ}}{\text{kcal}}\right)}$$

where the standard temperature for  $\left(\frac{\text{g mole}}{\text{scm}}\right)$  is 20°C;

[View or download PDF](#)

$C_i$  = Concentration of sample component  $i$  in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in §60.17); and

$H_i$  = Net heat of combustion of sample component  $i$ , kcal/g mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in §60.17) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity,  $V_{\max}$ , for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$$\text{Log}_{10}(V_{\max}) = (H_T + 28.8) / 31.7$$

$V_{\max}$  = Maximum permitted velocity, M/sec

28.8 = Constant

31.7 = Constant

$H_T$  = The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity,  $V_{\max}$ , for air-assisted flares shall be determined by the following equation.

$$V_{\max} = 8.706 + 0.7084 (H_T)$$

$V_{\max}$  = Maximum permitted velocity, m/sec

8.706 = Constant

0.7084 = Constant

$H_T$  = The net heating value as determined in paragraph (f)(3).

(g) *Alternative work practice for monitoring equipment for leaks.* Paragraphs (g), (h), and (i) of this section apply to all equipment for which the applicable subpart requires monitoring with a 40 CFR part 60, Appendix A-7, Method 21 monitor, except for closed vent systems, equipment designated as leakless, and equipment identified in the applicable subpart as having no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background. An owner or operator may use an optical gas imaging instrument instead of a 40 CFR part 60, Appendix A-7, Method 21 monitor. Requirements in the existing subparts that are specific to the Method 21 instrument do not apply under this section. All other requirements in the applicable subpart that are not addressed in paragraphs (g), (h), and (i) of this section apply to this standard. For example, equipment specification requirements, and non-Method 21 instrument recordkeeping and reporting requirements in the applicable subpart continue to apply. The terms defined in paragraphs (g)(1) through (5) of this section have meanings that are specific to the alternative work practice standard in paragraphs (g), (h), and (i) of this section.

(1) *Applicable subpart* means the subpart in 40 CFR parts 60, 61, 63, or 65 that requires monitoring of equipment with a 40 CFR part 60, Appendix A-7, Method 21 monitor.

(2) *Equipment* means pumps, valves, pressure relief valves, compressors, open-ended lines, flanges, connectors, and other equipment covered by the applicable subpart that require monitoring with a 40 CFR part 60, Appendix A-7, Method 21 monitor.

(3) *Imaging* means making visible emissions that may otherwise be invisible to the naked eye.

(4) *Optical gas imaging instrument* means an instrument that makes visible emissions that may otherwise be invisible to the naked eye.

(5) *Repair* means that equipment is adjusted, or otherwise altered, in order to eliminate a leak.

(6) *Leak* means:

(i) Any emissions imaged by the optical gas instrument;

(ii) Indications of liquids dripping;

(iii) Indications by a sensor that a seal or barrier fluid system has failed; or

(iv) Screening results using a 40 CFR part 60, Appendix A-7, Method 21 monitor that exceed the leak definition in the applicable subpart to which the equipment is subject.

(h) The alternative work practice standard for monitoring equipment for leaks is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, Appendix A-7, Method 21 monitor.

(1) An owner or operator of an affected source subject to CFR parts 60, 61, 63, or 65 can choose to comply with the alternative work practice requirements in paragraph (i) of this section instead of using the 40 CFR part 60, Appendix A-7, Method 21 monitor to identify leaking equipment. The owner or operator must document the equipment, process units, and facilities for which the alternative work practice will be used to identify leaks.

**SECTION 4. APPENDIX F (DRAFT)**  
**NSPS, Subpart A - General Provisions**

---

- (2) Any leak detected when following the leak survey procedure in paragraph (i)(3) of this section must be identified for repair as required in the applicable subpart.
- (3) If the alternative work practice is used to identify leaks, re-screening after an attempted repair of leaking equipment must be conducted using either the alternative work practice or the 40 CFR part 60, Appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart to which the equipment is subject.
- (4) The schedule for repair is as required in the applicable subpart.
- (5) When this alternative work practice is used for detecting leaking equipment, choose one of the monitoring frequencies listed in Table 1 to subpart A of this part in lieu of the monitoring frequency specified for regulated equipment in the applicable subpart. Reduced monitoring frequencies for good performance are not applicable when using the alternative work practice.
- (6) When this alternative work practice is used for detecting leaking equipment the following are not applicable for the equipment being monitored:
- (i) Skip period leak detection and repair;
  - (ii) Quality improvement plans; or
  - (iii) Complying with standards for allowable percentage of valves and pumps to leak.
- (7) When the alternative work practice is used to detect leaking equipment, the regulated equipment in paragraph (h)(1)(i) of this section must also be monitored annually using a 40 CFR part 60, Appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart. The owner or operator may choose the specific monitoring period (for example, first quarter) to conduct the annual monitoring. Subsequent monitoring must be conducted every 12 months from the initial period. Owners or operators must keep records of the annual Method 21 screening results, as specified in paragraph (i)(4)(vii) of this section.
- (i) An owner or operator of an affected source who chooses to use the alternative work practice must comply with the requirements of paragraphs (i)(1) through (i)(5) of this section.
- (1) Instrument Specifications. The optical gas imaging instrument must comply with the requirements in (i)(1)(i) and (i)(1)(ii) of this section.
- (i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in paragraph (i)(2) of this section. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.
  - (ii) Provide a date and time stamp for video records of every monitoring event.
- (2) Daily Instrument Check. On a daily basis, and prior to beginning any leak monitoring work, test the optical gas imaging instrument at the mass flow rate determined in paragraph (i)(2)(i) of this section in accordance with the procedure specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each camera configuration used during monitoring (for example, different lenses used), unless an alternative method to demonstrate daily instrument checks has been approved in accordance with paragraph (i)(2)(v) of this section.
- (i) Calculate the mass flow rate to be used in the daily instrument check by following the procedures in paragraphs (i)(2)(i)(A) and (i)(2)(i)(B) of this section.
- (A) For a specified population of equipment to be imaged by the instrument, determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level.

(B) Multiply the standard detection sensitivity level, corresponding to the selected monitoring frequency in Table 1 of subpart A of this part, by the mass fraction of detectable chemicals from the stream identified in paragraph (i)(2)(i)(A) of this section to determine the mass flow rate to be used in the daily instrument check, using the following equation.

$$E_{dic} = (E_{sds}) \sum_{i=1}^k x_i$$

Where:

$E_{dic}$  = Mass flow rate for the daily instrument check, grams per hour

$x_i$  = Mass fraction of detectable chemical(s)  $i$  seen by the optical gas imaging instrument, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level,  $E_{sds}$ .

$E_{sds}$  = Standard detection sensitivity level from Table 1 to subpart A, grams per hour

$k$  = Total number of detectable chemicals emitted from the leaking equipment and seen by the optical gas imaging instrument.

(ii) Start the optical gas imaging instrument according to the manufacturer's instructions, ensuring that all appropriate settings conform to the manufacturer's instructions.

(iii) Use any gas chosen by the user that can be viewed by the optical gas imaging instrument and that has a purity of no less than 98 percent.

(iv) Establish a mass flow rate by using the following procedures:

(A) Provide a source of gas where it will be in the field of view of the optical gas imaging instrument.

(B) Set up the optical gas imaging instrument at a recorded distance from the outlet or leak orifice of the flow meter that will not be exceeded in the actual performance of the leak survey. Do not exceed the operating parameters of the flow meter.

(C) Open the valve on the flow meter to set a flow rate that will create a mass emission rate equal to the mass rate specified in paragraph (i)(2)(i) of this section while observing the gas flow through the optical gas imaging instrument viewfinder. When an image of the gas emission is seen through the viewfinder at the required emission rate, make a record of the reading on the flow meter.

(v) Repeat the procedures specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each configuration of the optical gas imaging instrument used during the leak survey.

(vi) To use an alternative method to demonstrate daily instrument checks, apply to the Administrator for approval of the alternative under §60.13(i).

(3) Leak Survey Procedure. Operate the optical gas imaging instrument to image every regulated piece of equipment selected for this work practice in accordance with the instrument manufacturer's operating parameters. All emissions imaged by the optical gas imaging instrument are considered to be leaks and are subject to repair. All emissions visible to the naked eye are also considered to be leaks and are subject to repair.

(4) Recordkeeping. You must keep the records described in paragraphs (i)(4)(i) through (i)(4)(vii) of this section:

(i) The equipment, processes, and facilities for which the owner or operator chooses to use the alternative work practice.

(ii) The detection sensitivity level selected from Table 1 to subpart A of this part for the optical gas imaging instrument.



(iii) The analysis to determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, as specified in paragraph (i)(2)(i)(A) of this section.

(iv) The technical basis for the mass fraction of detectable chemicals used in the equation in paragraph (i)(2)(i)(B) of this section.

(v) The daily instrument check. Record the distance, per paragraph (i)(2)(iv)(B) of this section, and the flow meter reading, per paragraph (i)(2)(iv)(C) of this section, at which the leak was imaged. Keep a video record of the daily instrument check for each configuration of the optical gas imaging instrument used during the leak survey (for example, the daily instrument check must be conducted for each lens used). The video record must include a time and date stamp for each daily instrument check. The video record must be kept for 5 years.

(vi) Recordkeeping requirements in the applicable subpart. A video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. A video record can be used to meet the recordkeeping requirements of the applicable subparts if each piece of regulated equipment selected for this work practice can be identified in the video record. The video record must be kept for 5 years.

(vii) The results of the annual Method 21 screening required in paragraph (h)(7) of this section. Records must be kept for all regulated equipment specified in paragraph (h)(1) of this section. Records must identify the equipment screened, the screening value measured by Method 21, the time and date of the screening, and calibration information required in the existing applicable subpart.

(5) Reporting. Submit the reports required in the applicable subpart. Submit the records of the annual Method 21 screening required in paragraph (h)(7) of this section to the Administrator via e-mail to *CCG-AWP@EPA.GOV*.

[51 FR 2701, Jan. 21, 1986, as amended at 63 FR 24444, May 4, 1998; 65 FR 61752, Oct. 17, 2000; 73 FR 78209, Dec. 22, 2008]

#### **§ 60.19 General notification and reporting requirements.**

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word "calendar" is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without

**SECTION 4. APPENDIX F (DRAFT)**  
**NSPS, Subpart A - General Provisions**

changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f)

(1)

(i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

[59 FR 12428, Mar. 16, 1994, as amended at 64 FR 7463, Feb. 12, 1998]

**Table 1 to Subpart A to Part 60—Detection Sensitivity Levels (grams per hour)**

<b>Monitoring frequency per subpart<sup>a</sup></b>	<b>Detection sensitivity level</b>
Bi-Monthly	60
Semi-Quarterly	85
Monthly	100

<sup>a</sup>When this alternative work practice is used to identify leaking equipment, the owner or operator must choose one of the monitoring frequencies listed in this table in lieu of the monitoring frequency specified in the

**SECTION 4. APPENDIX F (DRAFT)**  
**NSPS, Subpart A - General Provisions**

---

applicable subpart. Bi-monthly means every other month. Semi-quarterly means twice per quarter. Monthly means once per month.

[73 FR 78211, Dec. 22, 2008]

**FEDERAL REGULATIONS ADOPTED BY REFERENCE**

In accordance with Rule 62-204.800, F.A.C., the following federal regulation in Title 40 of the Code of Federal Regulations (CFR) was adopted by reference. The original federal rule numbering has been retained.

*Federal Revision Date: March 20, 2009*

*State Rule Effective Date: November 18, 2009*

*Standardized Conditions Revision Date: February 5, 2010*

**Subpart KKKK—Standards of Performance for Stationary Combustion Turbines**

**Source:** 71 FR 38497, July 6, 2006, unless otherwise noted.

**Introduction****§ 60.4300 What is the purpose of this subpart?**

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

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

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

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

- (a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NO<sub>x</sub>) emission limits in §60.4320.
- (b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO<sub>x</sub> emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.
- (c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.
- (d) Combustion turbine test cells/stands are exempt from this subpart.

**Emission Limits****§ 60.4315 What pollutants are regulated by this subpart?**

The pollutants regulated by this subpart are nitrogen oxide (NO<sub>x</sub>) and sulfur dioxide (SO<sub>2</sub>).

**§ 60.4320 What emission limits must I meet for nitrogen oxides (NO<sub>x</sub>)?**

- (a) You must meet the emission limits for NO<sub>x</sub> specified in Table 1 to this subpart.
- (b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO<sub>x</sub>.

**§ 60.4325 What emission limits must I meet for NO<sub>x</sub> if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?**

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

**§ 60.4330 What emission limits must I meet for sulfur dioxide (SO<sub>2</sub>)?**

- (a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.
  - (1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO<sub>2</sub> in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;
  - (2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or
  - (3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain SO<sub>2</sub> in excess of 65 ng SO<sub>2</sub>/J (0.15 lb SO<sub>2</sub>/MMBtu) heat input.
- (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<sub>2</sub> 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<sub>2</sub>/J (0.42 lb SO<sub>2</sub>/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

**General Compliance Requirements**

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

- (a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.
- (b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:
  - (1) Determine compliance with the applicable NO<sub>x</sub> 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 NO<sub>x</sub> if I use water or steam injection?

- (a) If you are using water or steam injection to control NO<sub>x</sub> emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.
- (b) Alternatively, you may use continuous emission monitoring, as follows:
- (1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO<sub>x</sub> monitor and a diluent gas (oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>)) monitor, to determine the hourly NO<sub>x</sub> 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 NO<sub>x</sub> if I do not use water or steam injection?

- (a) If you are not using water or steam injection to control NO<sub>x</sub> emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO<sub>x</sub> emission result from the performance test is less than or equal to 75 percent of the NO<sub>x</sub> emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO<sub>x</sub> emission limit for the turbine, you must resume annual performance tests.
- (b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:
- (1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or
  - (2) Continuous parameter monitoring as follows:
    - (i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO<sub>x</sub> formation characteristics, and you must monitor these parameters continuously.
    - (ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO<sub>x</sub> mode.
    - (iii) For any turbine that uses SCR to reduce NO<sub>x</sub> emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

- (iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO<sub>x</sub> 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 NO<sub>x</sub>CEMS is chosen:

- (a) Each NO<sub>x</sub> diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO<sub>x</sub> diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.
- (b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO<sub>x</sub> monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO<sub>x</sub> emission rate for the hour.
- (c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.
- (d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.
- (e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

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

For purposes of identifying excess emissions:

- (a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).
- (b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO<sub>x</sub> and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO<sub>x</sub> emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O<sub>2</sub> concentration exceeds 19.0 percent O<sub>2</sub> (or the hourly average CO<sub>2</sub> concentration is less than 1.0 percent CO<sub>2</sub>), a diluent cap value of 19.0 percent O<sub>2</sub> or 1.0 percent CO<sub>2</sub> (as applicable) may be used in the emission calculations.
- (c) Correction of measured NO<sub>x</sub> concentrations to 15 percent O<sub>2</sub> is not allowed.

## APPENDIX G

### NSPS, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

- (d) If you have installed and certified a NO<sub>x</sub> diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).
- (e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.
- (f) Calculate the hourly average NO<sub>x</sub> 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:

$$E = \frac{(\text{NO}_x)_h * (\text{HI})_h}{P} \quad (\text{Eq. 1})$$

Where:

E = hourly NO<sub>x</sub> emission rate, in lb/MWh,

(NO<sub>x</sub>)<sub>h</sub> = hourly NO<sub>x</sub> emission rate, in lb/MMBtu,

(HI)<sub>h</sub> = 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:

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

Where:

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

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

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

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

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 10<sup>6</sup> = 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 = NO<sub>x</sub> emission rate in lb/MWh,

(NO<sub>x</sub>)<sub>m</sub> = NO<sub>x</sub> 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 on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO<sub>x</sub> emission controls. The plan must:
- (1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO<sub>x</sub> 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 NO<sub>x</sub> emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

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

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

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

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input for units located in continental areas and 180 ng SO<sub>2</sub>/J (0.42 lb SO<sub>2</sub>/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

- (a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO<sub>2</sub>/J (0.42 lb SO<sub>2</sub>/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<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input for continental areas or 180 ng SO<sub>2</sub>/J (0.42 lb SO<sub>2</sub>/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

**NSPS, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines**

daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

- (2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:
  - (i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.
  - (ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.
  - (iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.
  - (iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

**Reporting**

**§ 60.4375 What reports must I submit?**

- (a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.
- (b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

**§ 60.4380 How are excess emissions and monitor downtime defined for NO<sub>x</sub>?**

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

- (a) For turbines using water or steam to fuel ratio monitoring:
  - (1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO<sub>x</sub> control will also be considered an excess emission.
  - (2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.
  - (3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.
- (b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

- (1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO<sub>x</sub> emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a “4-hour rolling average NO<sub>x</sub> emission rate” is the arithmetic average of the average NO<sub>x</sub> emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO<sub>x</sub> emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO<sub>x</sub> emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a “30-day rolling average NO<sub>x</sub> emission rate” is the arithmetic average of all hourly NO<sub>x</sub> emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO<sub>x</sub> emissions rates for the preceding 30 unit operating days if a valid NO<sub>x</sub> emission rate is obtained for at least 75 percent of all operating hours.
  - (2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO<sub>x</sub> concentration, CO<sub>2</sub> or O<sub>2</sub> 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 NO<sub>x</sub> emission controls:
- (1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.
  - (2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

#### **§ 60.4385 How are excess emissions and monitoring downtime defined for SO<sub>2</sub>?**

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

- (a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.
- (b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.
- (c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

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

- (a) If you operate an emergency combustion turbine, you are exempt from the NO<sub>x</sub> limit and must submit an initial report to the Administrator stating your case.
- (b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO<sub>x</sub> 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 NO<sub>x</sub>?**

- (a) You must conduct an initial performance test, as required in §60.8. Subsequent NO<sub>x</sub> performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).
  - (1) There are two general methodologies that you may use to conduct the performance tests. For each test run:
    - (i) Measure the NO<sub>x</sub> concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO<sub>x</sub> emission rate:

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

Where:

E = NO<sub>x</sub> emission rate, in lb/MWh

1.194 × 10<sup>-7</sup> = conversion constant, in lb/dscf-ppm

(NO<sub>x</sub>)<sub>c</sub> = average NO<sub>x</sub> concentration for the run, in ppm

Q<sub>std</sub> = stack gas volumetric flow rate, in dscf/hr

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

- (ii) Measure the NO<sub>x</sub> and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO<sub>x</sub> emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO<sub>x</sub> emission rate in lb/MWh.

## APPENDIX G

### NSPS, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

- (2) Sampling traverse points for NO<sub>x</sub> and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.
- (3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:
  - (i) You may perform a stratification test for NO<sub>x</sub> and diluent pursuant to
    - (A) [Reserved], or
    - (B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.
  - (ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:
    - (A) If each of the individual traverse point NO<sub>x</sub> concentrations is within  $\pm 10$  percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than  $\pm 5$  ppm or  $\pm 0.5$  percent CO<sub>2</sub>(or O<sub>2</sub>) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO<sub>x</sub> concentration during the stratification test; or
    - (B) For turbines with a NO<sub>x</sub> standard greater than 15 ppm @ 15% O<sub>2</sub>, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO<sub>x</sub> concentrations is within  $\pm 5$  percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than  $\pm 3$  ppm or  $\pm 0.3$  percent CO<sub>2</sub>(or O<sub>2</sub>) from the mean for all traverse points; or
    - (C) For turbines with a NO<sub>x</sub> standard less than or equal to 15 ppm @ 15% O<sub>2</sub>, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO<sub>x</sub> concentrations is within  $\pm 2.5$  percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than  $\pm 1$  ppm or  $\pm 0.15$  percent CO<sub>2</sub>(or O<sub>2</sub>) from the mean for all traverse points.
- (b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.
  - (1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.
  - (2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO<sub>x</sub> emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.
  - (3) If water or steam injection is used to control NO<sub>x</sub> with no additional post-combustion NO<sub>x</sub> control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be

used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NO<sub>x</sub> emission limit.

- (4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO<sub>x</sub> emission rate at each tested level meets the applicable emission limit in §60.4320.
- (5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.
- (6) The ambient temperature must be greater than 0 °F during the performance test.

**§ 60.4405 How do I perform the initial performance test if I have chosen to install a NO<sub>x</sub>-diluent CEMS?**

If you elect to install and certify a NO<sub>x</sub>-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

- (a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.
- (b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.
- (c) Use the test data both to demonstrate compliance with the applicable NO<sub>x</sub> emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.
- (d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO<sub>x</sub> emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

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

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO<sub>x</sub> emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

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

- (a) You must conduct an initial performance test, as required in §60.8. Subsequent SO<sub>2</sub> 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).



## APPENDIX G

### NSPS, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

- (2) Measure the SO<sub>2</sub> 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 SO<sub>2</sub> emission rate:

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

Where:

E = SO<sub>2</sub> emission rate, in lb/MWh

$1.664 \times 10^{-7}$  = conversion constant, in lb/dscf-ppm

(SO<sub>2</sub>)<sub>c</sub> = average SO<sub>2</sub> concentration for the run, in ppm

Q<sub>std</sub> = stack gas volumetric flow rate, in dscf/hr

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

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

*Biogas* means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO<sub>2</sub>.

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

*Combined heat and power combustion turbine* means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

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

*Combustion turbine test cell/stand* means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

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

*Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

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

*Emergency combustion turbine* means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

*Excess emissions* means a specified averaging period over which either (1) the NO<sub>x</sub> 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,

## APPENDIX G

### NSPS, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

*Noncontinental area* means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

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

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

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

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

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

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

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

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

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

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO <sub>x</sub> emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O <sub>2</sub> or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O <sub>2</sub> or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O <sub>2</sub> or 150 ng/J of useful output

# APPENDIX G

## NSPS, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO <sub>x</sub> emission standard
		(1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O <sub>2</sub> or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O <sub>2</sub> or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O <sub>2</sub> or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O <sub>2</sub> or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O <sub>2</sub> or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O <sub>2</sub> or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O <sub>2</sub> or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O <sub>2</sub> or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O <sub>2</sub> or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O <sub>2</sub> or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O <sub>2</sub> or 110 ng/J of useful output (0.86 lb/MWh).

SECTION 4. APPENDIX H (DRAFT)  
Heat Input vs. CT Inlet Temperature Curve

Lake Cogen Heat Input Curve  
Inlet Temperature vs Heat Input

