BOARD OF SUPERVISORS

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COUNTY OF SAN DIEGO

AIR POLLUTION CONTROL DISTRICT

DATE: February 25, 2009

TO: San Diego County Air Pollution Control Board

SUBJECT: REPEAL EXISTING SUBPART GG OF REGULATION X AND ADOPT BY REFERENCE FEDERAL NEW SOURCE PERFORMANCE STANDARDS SUBPARTS GG AND KKKK FOR STATIONARY COMBUSTION TURBINES (District: All)

SUMMARY:

Overview

New Source Performance Standards are periodically issued by the U.S. Environmental Protection Agency and apply throughout the country to specified new, modified, and reconstructed stationary sources of air pollution such as power plants. The U.S. Environmental Protection Agency may delegate authority for administering and enforcing a standard to state or local air agencies.

The Air Pollution Control District's Regulation X contains federal New Source Performance Standards that governs stationary sources of air pollution and that were locally adopted and for which delegation was received from the U.S. Environmental Protection Agency. Periodic amendments to Regulation X are necessary to incorporate new or amended federal New Source Performance Standards by reference. Amendments are now proposed to repeal an outdated federal version of Subpart GG (Stationary Gas Turbines) and to adopt the current federal version of Subparts GG and KKKK (Stationary Combustion Turbines).

The Air Pollution Control District proposes seeking delegation from the U.S. Environmental Protection Agency to locally administer and enforce Subparts GG and KKKK following their local adoption by reference. Delegated authority provides a single, local point of reference for air pollution control requirements relating to a New Source Performance Standard and assists local businesses in streamlining their communication.

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Recommendation(s)
CHIEF ADMINISTRATIVE OFFICER

1. Find that it can be seen with certainty that there is no possibility that the adoption of the proposed amendments to Regulation X may have a significant effect on the environment, and the adoption of those proposed amendments is exempt from the provisions of the California Environmental Quality Act pursuant to California Code of Regulations, Title 14, Section 15061(b)(3).

2. Adopt the resolution titled Resolution Repealing Existing Regulation X Subpart GG and Adopting By Reference Federal New Source Performance Standard Subparts GG and KKKK to Regulation X of the Rules and Regulations of the San Diego County Air Pollution Control District.

3. Direct the Air Pollution Control Officer to request delegation from the U.S. Environmental Protection Agency to locally implement and enforce federal Subparts GG and KKKK.

Fiscal Impact
The recommended actions will have no fiscal impact on the Air Pollution Control District. Once delegated authority is received from the U.S. Environmental Protection Agency, the amendments will be implemented and enforced locally using existing staffing and funding identified in the Air Pollution Control District's Operational Plan.

Business Impact Statement
Federal delegation of authority to locally implement and enforce a New Source Performance Standard is preferred by affected businesses. Businesses can continue to work with the Air Pollution Control District to resolve any compliance issues that may arise rather than dealing directly with the federal agency, thereby streamlining communication.

The recent federal amendments to Subpart GG may result in additional monitoring requirements for eight of the 27 turbine facilities in the county that have not already installed a continuous emission monitoring system or that do not perform continuous monitoring of parameters indicative of their units' emissions. The additional monitoring requirements of amended Subpart GG are anticipated to require relatively simple modifications performed at a minimal cost to these facilities.

Subpart KKKK is applicable to five existing and six proposed turbines in San Diego

County. However, Subpart KKKK results in no change in requirements for these facilities, because it applies to new combustion turbines that must install best available control technology pursuant to the District's New Source Review rules, developed pursuant to more stringent State requirements.

Advisory Board Statement
At its meeting on November 12, 2008, with a quorum present, the Air Pollution Control District Advisory Committee expressed support of the Air Pollution Control District's recommendations.

BACKGROUND:
Federal New Source Performance Standards (NSPSs) are regulations that establish minimum air pollution control standards for specific industries. They are issued by the U.S. Environmental Protection Agency (EPA) as Subparts of Title 40, Chapter 1, Part 60, of the Code of Federal Regulations and apply uniformly throughout the country. EPA can enforce an NSPS, but often delegates primary implementation and enforcement authority to state and local air pollution control agencies.

Subparts GG and KKKK each apply to specific combustion turbines and establish emission limits for nitrogen oxides (NO_x) and sulfur dioxides (SO_2). Subpart KKKK applies to turbines built after February 18, 2005, while Subpart GG applies to turbines built prior to that date and after October 3, 1977. Subpart KKKK reflects advancements in emission control technologies and turbine design whereas the emission standards in Subpart GG, applicable to existing older turbines, have remained relatively unchanged since first promulgated in 1979. Most other requirements of the two regulations are the same, including reporting, record keeping, and test methods.

Subpart GG was last adopted, by reference, on October 17, 2001 (APCB #3), and delegation was received from EPA on January 3, 2008. EPA recently modified the federal regulation to add additional alternative testing and monitoring procedures, and to harmonize the provisions of Subpart GG with the continuous monitoring requirements of the federal acid rain program. Consequently, the current Regulation X version of Subpart GG is now outdated. The Air Pollution Control District (District) proposes to repeal the older version from Regulation X and adopt, by reference, the updated version of Subpart GG.

Subpart KKKK was promulgated by EPA on July 6, 2006, and is not currently included in the District's Regulation X. The District proposes to adopt it by reference for inclusion in Regulation X.

If Subparts GG and KKKK are adopted by reference the District will then petition EPA for delegation of implementation and enforcement authority. Routine approval by EPA is anticipated. Delegation will allow for more efficient local implementation of the Subparts, both for the affected facilities and the District.

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A public workshop was held on November 3, 2008. No significant issues were raised and there was no opposition to the proposed actions.

Compliance with Board Policy on Adopting New Rules

On February 2, 1993, the Board directed that, with the exception of a regulation requested by business or a regulation for which a socioeconomic impact assessment is not required, no new or revised regulation shall be implemented unless specifically required by federal or State law. The proposed adoption of federal Subparts GG and KKKK is consistent with this Board directive.

Environmental Statement

The California Environmental Quality Act (CEQA) requires an environmental review for certain actions. The District has conducted a preliminary review of whether CEQA applies to amending Regulation X of the District Rules and Regulations by updating federal Subpart GG and adding federal Subpart KKKK by reference. Because all affected sources are already subject to the federal regulations, it is certain there is no possibility that this action may have a significant adverse effect on the environment. Therefore, the adoption of amendments to Regulation X is exempt from the provisions of CEQA pursuant to California Code of Regulations, Title 14, Section 15061(b)(3).

Linkage to the County of San Diego's Strategic Plan

The County's five-year strategic plan includes an Environment Strategic Initiative with an objective to reduce environmental risk through regulation, intergovernmental collaboration, and the leveraging of public and private resources. Local adoption and enforcement of federal Subparts GG and KKKK on sources that may emit sizeable amounts of harmful emissions fulfills the objective to restore air quality, thus protecting public health and the environment.

Respectfully submitted,

Chandra Wallar

CHANDRA L. WALLAR
Deputy Chief Administrative Officer

Robert Kard

ROBERT KARD
Air Pollution Control Officer

ATTACHMENT(S)

Attachment A - Resolution Repealing Existing Regulation X Subpart GG and Adopting By Reference Federal New Source Performance Standard (NSPS) Subparts GG and KKKK to Regulation X of the Rules and Regulations of the San Diego County Air Pollution Control District.

SUBJECT: REPEAL EXISTING SUBPART GG OF REGULATION X AND ADOPT BY REFERENCE FEDERAL NEW SOURCE PERFORMANCE STANDARDS SUBPARTS GG AND KKKK FOR STATIONARY COMBUSTION TURBINES (District: All)

Attachment B - Change Copy of Regulation X

Attachment C - Federal New Source Performance Standard Subparts GG and KKKK

Attachment D - Workshop Report

SUBJECT: REPEAL EXISTING SUBPART GG OF REGULATION X AND ADOPT BY REFERENCE FEDERAL NEW SOURCE PERFORMANCE STANDARDS SUBPARTS GG AND KKKK FOR STATIONARY COMBUSTION TURBINES (District: All)

AGENDA ITEM INFORMATION SHEET

CONCURRENCE(S)

COUNTY COUNSEL REVIEW	[X] Yes	
Written disclosure per County Charter §1000.1 required?	[] Yes	[X] No
GROUP/AGENCY FINANCE DIRECTOR	[] Yes	[X] N/A
CHIEF FINANCIAL OFFICER	[] Yes	[X] N/A
Requires Four Votes	[] Yes	[X] No
GROUP/AGENCY INFORMATION TECHNOLOGY DIRECTOR	[] Yes	[X] N/A
COUNTY TECHNOLOGY OFFICE	[] Yes	[X] N/A
DEPARTMENT OF HUMAN RESOURCES	[] Yes	[X] N/A

Other Concurrence(s): N/A

ORIGINATING DEPARTMENT: Air Pollution Control District, County of San Diego

CONTACT PERSON(S):

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AUTHORIZED REPRESENTATIVE: ____________________

ROBERT J. KARD
Air Pollution Control Officer

SUBJECT: REPEAL EXISTING SUBPART GG OF REGULATION X AND ADOPT BY REFERENCE FEDERAL NEW SOURCE PERFORMANCE STANDARDS SUBPARTS GG AND KKKK FOR STATIONARY COMBUSTION TURBINES (District: All)

AGENDA ITEM INFORMATION SHEET
(continued)

PREVIOUS RELEVANT BOARD ACTIONS:
October 17, 2001 (APCB #3), Adoption of Amendments to Regulation X Repealing and Adopting by Reference the Following New Source Performance Standards (NSPS): Subpart D – NSPS for Fossil Fuel-Fired Steam Generators, Subpart Da – NSPS for Electric Utility Steam Generating Units, and Subpart GG – NSPS for Stationary Gas Turbines; July 25, 1995 (APCB #1), Approval of Adoption by Reference Procedure; February 2, 1993 (APCB #2), Delayed implementation of new or revised regulations unless requested by business, specifically ordered by federal or State law, or for which a socioeconomic impact assessment is not required; November 24, 1982 (APCB #1), Adoption of Subpart GG to Regulation X.

BOARD POLICIES APPLICABLE:
N/A

BOARD POLICY STATEMENTS:
N/A

CONTRACT AND/OR REQUISITION NUMBER(S):
N/A

ATTACHMENT A

Re: Rules and Regulations of the)
Air Pollution Control District. . . .)
of San Diego County . . . .)

RESOLUTION REPEALING EXISTING REGULATION X SUBPART GG AND ADOPTING BY REFERENCE FEDERAL NEW SOURCE PERFORMANCE STANDARD (NSPS) SUBPARTS GG AND KKKK TO REGULATION X OF THE RULES AND REGULATIONS OF THE SAN DIEGO COUNTY AIR POLLUTION CONTROL DISTRICT

On motion of Member **Roberts**, seconded by Member **Horn**, the following resolution is adopted:

WHEREAS, the San Diego County Air Pollution Control Board, pursuant to Section 40702 of the Health and Safety Code, adopted Rules and Regulations of the Air Pollution Control District of San Diego County; and

WHEREAS, said Board now desires to amend said Rules and Regulations; and

WHEREAS, notice has been given and a public hearing has been had relating to the amendment of said Rules and Regulations pursuant to Section 40725 of the Health and Safety Code; and

WHEREAS, pursuant to section 40727 of the Health and Safety Code, the San Diego County Air Pollution Control Board makes the following findings:

(1) (Necessity) The repeal of existing Regulation X Subpart GG and adoption by reference of federal NSPS Subparts GG and KKKK to Regulation X is necessary in order to receive delegation from the U.S. Environmental Protection Agency to implement and enforce federal NSPS Subparts GG and KKKK, as required pursuant to the Section 105 grant from U.S. Environmental Protection Agency to the Air Pollution Control District;

(2) (Authority) The repeal of existing Regulation X Subpart GG and adoption by reference of federal NSPS Subparts GG and KKKK to Regulation X is authorized by Health and Safety Code section 40702;

(3) (Clarity) Federal NSPS Subparts GG and KKKK can be easily understood by persons directly affected by them;

(4) (Consistency) The repeal of existing Regulation X Subpart GG and adoption by reference of federal NSPS Subparts GG and KKKK to Regulation X merely incorporates by reference the federal NSPS Subparts GG and KKKK adopted pursuant to Section 111 of the Clean Air Act (42 U.S.C. § 7411), and federal NSPS Subparts GG and KKKK align with, and not in conflict with or contrary to, existing statutes, court decisions, and State and federal regulations;

(5) (Non-duplication) The repeal of existing Regulation X Subpart GG and adoption by reference of federal NSPS Subparts GG and KKKK to Regulation X will not duplicate existing district or federal requirements, but merely incorporates the federal NSPS Subparts;

(6) (Reference) The repeal of existing Regulation X Subpart GG and adoption by reference of Federal NSPS Subparts GG and KKKK to Regulation X is necessary to receive delegation from the U.S. Environmental Protection Agency to implement and enforce federal NSPS Subparts GG and KKKK in accordance with Clean Air Act section 111 (42 U.S.C. § 7411); and

WHEREAS, the Air Pollution Control Board further finds that an analysis of existing requirements applicable to the source or category is not required by Section 40727.2 of the Health and Safety Code because the proposed addition of Subparts GG and KKKK does not impose new or more stringent requirements; and

WHEREAS, the Air Pollution Control Board further finds pursuant to Health and Safety Code section 40001 that the addition by reference of federal NSPS Subparts GG and KKKK is required to receive delegation to implement the federal NSPS and will promote the attainment of ambient air quality standards; and

WHEREAS, the Air Pollution Control Board further finds that an assessment of socioeconomic impacts is not required by Health and Safety Code section 40728.5 for addition by reference of federal NSPS Subparts GG and KKKK because it will not significantly affect air quality or emission limitations,

NOW THEREFORE IT IS RESOLVED AND ORDERED by the San Diego County Air Pollution Control Board that the Rules and Regulations of the Air Pollution Control District of San Diego County be and hereby are amended as follows:

The proposed amendment to the Preamble to Regulation X modifying Subpart GG and adding Subpart KKKK by reference is to read as follows:

REGULATION X. STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (NSPS) (Rev. Effective (*date of adoption*))

The provisions of Part 60, Chapter I, Title 40, of the Code of Federal Regulations, (40 CFR 60), applicable to the subparts listed in this Regulation are hereby adopted by reference on the date shown and made part of the Air Pollution Control District Rules and Regulations. Whenever any source is subject to more than one rule, regulation, provision, or requirement relating to the control of any air contaminant, in cases of conflict or duplication the most stringent rule, regulation, provision, or requirement shall apply.

All new sources of air pollution and all modified or reconstructed sources of air pollution shall comply with the applicable standards, criteria, and requirements set forth herein. For the purpose of this Regulation, the word "Administrator" as used in 40 CFR 60 shall mean the Air Pollution Control Officer of the San Diego County Air Pollution Control District, except that the Air Pollution Control Officer shall not be empowered to approve alternate test methods, alternate standards or work practices. Other deviations, if any, from the provisions of 40 CFR 60 which are adopted by the Air Pollution Control Board are noted in the reference to the affected Subpart.

The U.S. Environmental Protection Agency (EPA) retains concurrent enforcement authority for these standards pursuant to Section 113 of the federal Clean Air Act, as amended, if the EPA Administrator desires to exercise it, including those not yet adopted by the Air Pollution Control District.

The addition of federal Subparts by reference to Regulation X shall take effect and be in force on the date of delegation of enforcement authority to the San Diego County Air Pollution Control District by EPA.

SUBPART D
40CFR60.40-46

STANDARDS OF PERFORMANCE FOR FOSSIL-FUEL-FIRED STEAM GENERATORS FOR WHICH CONSTRUCTION IS COMMENCED AFTER AUGUST 17, 1971

FR Citation	**Adoption Date**	**Delegation Date**
39 FR 20791, June 14, 1974	October 17, 2001	January 3, 2008
40 FR 2803, Jan. 16, 1975	October 17, 2001	January 3, 2008
40 FR 46256, Oct. 6, 1975	October 17, 2001	January 3, 2008
41 FR 51398, Nov. 22, 1976	October 17, 2001	January 3, 2008
42 FR 37936, July 25, 1977	October 17, 2001	January 3, 2008
42 FR 61537, Dec. 5, 1977	October 17, 2001	January 3, 2008
43 FR 9278, Mar. 7, 1978	October 17, 2001	January 3, 2008
44 FR 33612, June 17, 1979	October 17, 2001	January 3, 2008
44 FR 76787, Dec. 28, 1979	October 17, 2001	January 3, 2008
45 FR 36077, May 29, 1980	October 17, 2001	January 3, 2008
45 FR 47146, July 14, 1980	October 17, 2001	January 3, 2008
46 FR 57498, Nov. 24, 1981	October 17, 2001	January 3, 2008
48 FR 3736, Jan. 27, 1983	October 17, 2001	January 3, 2008
51 FR 42797, Nov. 25, 1986	October 17, 2001	January 3, 2008
52 FR 28954, Aug. 4, 1987	October 17, 2001	January 3, 2008
54 FR 6662, Feb. 14, 1989	October 17, 2001	January 3, 2008
54 FR 21344, May 17, 1989	October 17, 2001	January 3, 2008
55 FR 5212, Feb. 14, 1990	October 17, 2001	January 3, 2008
61 FR 49976, Sept. 24, 1996	October 17, 2001	January 3, 2008
65 FR 61752, Oct. 17, 2000	Not Yet Adopted	
72 FR 32717, June 13, 2007	Not Yet Adopted	

SUBPART Da
40CFR60.40a-49a

STANDARDS OF PERFORMANCE FOR ELECTRIC UTILITY STEAM GENERATING UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER SEPTEMBER 18, 1978

FR Citation	**Adoption Date**	**Delegation Date**
44 FR 33613, June 11, 1979	October 17, 2001	January 3, 2008
48 F4 3737, Jan. 27, 1983	October 17, 2001	January 3, 2008
54 FR 6663, Feb. 14, 1989	October 17, 2001	January 3, 2008
54 FR 21344, May 17, 1989	October 17, 2001	January 3, 2008
55 FR 5212, Feb. 14, 1990	October 17, 2001	January 3, 2008
55 FR 18876, May 7, 1990	October 17, 2001	January 3, 2008
63 FR 49453, Sept. 16, 1998	October 17, 2001	January 3, 2008
64 FR 7464, Feb. 12, 1999	October 17, 2001	January 3, 2008
65 FR 61752, Oct. 17, 2000	October 17, 2001	January 3, 2008
66 FR 18551, April 10, 2001	October 17, 2001	January 3, 2008
66 FR 31178, June 11, 2001	October 17, 2001	January 3, 2008

SUBPART Da continued

	66 FR 42610, Aug. 14, 2001	Not Yet Adopted
	70 FR 28653, May 18, 2005	Not Yet Adopted
	70 FR 51268, Aug. 30, 2005	Not Yet Adopted
	71 FR 9876, Feb. 27, 2006	Not Yet Adopted
	71 FR 33399, June 9, 2006	Not Yet Adopted
	72 FR 32722, June 13, 2007	Not Yet Adopted

SUBPART Db
40CFR60.40b-49b

STANDARDS OF PERFORMANCE FOR INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

FR Citation	Adoption Date	Delegation Date
51 FR 42768, Nov. 25, 1986	April 25, 2001	January 3, 2008
52 FR 47842, Dec. 16, 1987	April 25, 2001	January 3, 2008
54 FR 51824, Dec. 18, 1989	April 25, 2001	January 3, 2008
54 FR 51819, Dec. 18, 1989	April 25, 2001	January 3, 2008
55 FR 5212, Feb. 14, 1990	April 25, 2001	January 3, 2008
55 FR 18876, May 7, 1990	April 25, 2001	January 3, 2008
60 FR 28062, May 30, 1995	April 25, 2001	January 3, 2008
61 FR 14031, Mar. 29, 1996	April 25, 2001	January 3, 2008
62 FR 52641, Oct. 8, 1997	April 25, 2001	January 3, 2008
63 FR 49454, Sept. 16, 1998	April 25, 2001	January 3, 2008
64 FR 7464, Feb. 12, 1999	April 25, 2001	January 3, 2008
65 FR 13243, Mar. 13, 2000	April 25, 2001	January 3, 2008
65 FR 61752, Oct. 17, 2000	Not Yet Adopted	
66 FR 18553, April 10, 2001	Not Yet Adopted	
66 FR 42610, Aug. 14, 2001	Not Yet Adopted	
66 FR 49834, Oct. 1, 2001	Not Yet Adopted	
69 FR 40773, July 7, 2004	Not Yet Adopted	
71 FR 9881, Feb. 27, 2006	Not Yet Adopted	
71 FR 33400, June 9, 2006	Not Yet Adopted	
72 FR 32742, June 13, 2007	Not Yet Adopted	

SUBPART Dc
40CFR60.40c-48c

STANDARDS OF PERFORMANCE FOR SMALL INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

FR Citation	Adoption Date	Delegation Date
55 FR 37683, Sept. 12, 1990	Aug. 13, 1997	June 24, 1998
61 FR 20736, May 8, 1996	Aug. 13, 1997	June 24, 1998
64 FR 7465, Feb. 12, 1999	Not Yet Adopted	
65 FR 61752, Oct. 17, 2000	Not Yet Adopted	
71 FR 9884, Feb. 27, 2006	Not Yet Adopted	
72 FR 32759, June 13, 2007	Not Yet Adopted	

SUBPART Eb
40CFR60.50b-59b

STANDARDS OF PERFORMANCE FOR LARGE MUNICIPAL WASTE COMBUSTORS FOR WHICH CONSTRUCTION IS COMMENCED AFTER SEPTEMBER 20, 1994 OR FOR WHICH MODIFCATION OR RECONSTRUCTION COMMENCED AFTER JUNE 19, 1996

FR Citation	Adoption Date	Delegation Date
60 FR 65419, Dec. 19, 1995	June 20, 2007	January 3, 2008
62 FR 45120, Aug. 25, 1997	June 20, 2007	January 3, 2008

SUBPART Eb continued

62 FR 45125, Aug. 25, 1997	June 20, 2007	January 3, 2008
65 FR 61753, Oct. 17, 2000	June 20, 2007	January 3, 2008
66 FR 36476, July 12, 2001	June 20, 2007	January 3, 2008
66 FR 57827, Nov. 16, 2001	June 20, 2007	January 3, 2008
71 FR 27335, May 10, 2006	June 20, 2007	January 3, 2008

SUBPART Ec
40CFR60.50c-58c

STANDARDS OF PERFORMANCE FOR HOSPITAL/MEDICAL/ INFECTIOUS WASTE INCINERATORS FOR WHICH CONSTRUCTION IS COMMENCED AFTER JUNE 20, 1996

FR Citation	**Adoption Date**	**Delegation Date**
62 FR 48382, Sept. 15, 1997	June 20, 2007	January 3, 2008
65 FR 61753, Oct. 17, 2000	June 20, 2007	January 3, 2008

SUBPART K
40CFR60.110-113

STANDARDS OF PERFORMANCE FOR STORAGE VESSELS FOR PETROLEUM LIQUIDS FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JUNE 11, 1973, AND PRIOR TO MAY 19, 1978

FR Citation	**Adoption Date**	**Delegation Date**
39 FR 9317, March 8, 1974	June 20, 2007	January 3, 2008
39 FR 13776, April 17, 1974	June 20, 2007	January 3, 2008
39 FR 20794, June 14, 1974	June 20, 2007	January 3, 2008
42 FR 37937, July 25, 1977	June 20, 2007	January 3, 2008
45 FR 23379, April 4, 1980	June 20, 2007	January 3, 2008
48 FR 3737, Jan. 27, 1983	June 20, 2007	January 3, 2008
52 FR 11429, April 8, 1987	June 20, 2007	January 3, 2008
65 FR 61755, Oct. 17, 2000	June 20, 2007	January 3, 2008

SUBPART Ka
40CFR60.110a-115a

STANDARDS OF PERFORMANCE FOR STORAGE VESSELS FOR PETROLEUM LIQUIDS FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER May 18, 1978, AND PRIOR TO July 23, 1984

FR Citation	**Adoption Date**	**Delegation Date**
45 FR 23379, April 4, 1980	June 20, 2007	January 3, 2008
45 FR 83229, Dec. 18,1980	June 20, 2007	January 3, 2008
48 FR 3737, Jan. 27, 1983	June 20, 2007	January 3, 2008
52 FR 11429, April 8, 1987	June 20, 2007	January 3, 2008
65 FR 61756, Oct. 17, 2000	June 20, 2007	January 3, 2008
65 FR 78275, Dec. 14, 2000	June 20, 2007	January 3, 2008

SUBPART Kb
40CFR60.110b-117b

STANDARDS OF PERFORMANCE FOR VOLATILE ORGANIC LIQUID STORAGE VESSELS (INCLUDING PETROLEUM LIQUID STORAGE VESSELS) FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JULY 23, 1984

FR Citation	**Adoption Date**	**Delegation Date**
52 FR 11429, April 8, 1987	June 20, 2007	January 3, 2008
52 FR 22780, June 16, 1987	June 20, 2007	January 3, 2008
54 FR 32973, Aug. 11, 1989	June 20, 2007	January 3, 2008
62 FR 52641, Oct. 8, 1997	June 20, 2007	January 3, 2008

SUBPART Kb continued

	FR Citation	Adoption Date	Delegation Date
	65 FR 61756, Oct. 17, 2000	June 20, 2007	January 3, 2008
	65 FR 78275, Dec. 14, 2000	June 20, 2007	January 3, 2008
	68 FR 59332, Oct. 15, 2003	June 20, 2007	January 3, 2008

SUBPART GG
40CFR60.330-335

STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES

FR Citation	**Adoption Date**	**Delegation Date**
44 FR 52798, Sept. 10, 1979	October 17, 2001	January 3, 2008
47 FR 3770, Jan. 27, 1982	October 17, 2001	January 3, 2008
52 FR 42434, Nov. 5, 1987	October 17, 2001	January 3, 2008
54 FR 6675 Feb. 14, 1989	October 17, 2001	January 3, 2008
54 FR 27016, June 27, 1989	October 17, 2001	January 3, 2008
65 FR 61759, Oct. 17, 2000	*(date of adoption)*	
69 FR 41359, July 8, 2004	*(date of adoption)*	
71 FR 9458, Feb. 24, 2006	*(date of adoption)*	

SUBPART AAA
40CFR60.530-539b

STANDARDS OF PERFORMANCE FOR NEW RESIDENTIAL WOOD HEATERS

FR Citation	**Adoption Date**	**Delegation Date**
53 FR 5873, Feb. 26, 1988	April 12, 2000	January 3, 2008
53 FR 12009, April 12, 1988	April 12, 2000	January 3, 2008
53 FR 14889, April 26, 1988	April 12, 2000	January 3, 2008
57 FR 5328, Feb. 13, 1992	April 12, 2000	January 3, 2008
60 FR 33925, June 29, 1995	April 12, 2000	January 3, 2008
63 FR 64874, Nov. 24, 1998	April 12, 2000	January 3, 2008
64 FR 7466, Feb. 12, 1999	April 12, 2000	January 3, 2008
65 FR 61763, Oct. 17, 2000	Not Yet Adopted	

SUBPART OOO
40CFR60.670-676

STANDARDS OF PERFORMANCE FOR NONMETALLIC MINERAL PROCESSING PLANTS

FR Citation	**Adoption Date**	**Delegation Date**
50 FR 31328, Aug. 1, 1985	April 28, 1999	May 28, 2002
51 FR 31337, Aug. 1, 1985	Not Yet Adopted	
54 FR 6680, Feb. 14, 1989	Not Yet Adopted	
62 FR 31351, June 9, 1997	April 28, 1999	May 28, 2002
65 FR 61778, Oct. 17, 2000	Not Yet Adopted	

SUBPART UUU
40CFR60.730-737

STANDARDS OF PERFORMANCE FOR CALCINERS AND DRYERS IN MINERAL INDUSTRIES

FR Citation	**Adoption Date**	**Delegation Date**
57 FR 44503, Sept. 28, 1992	Nov. 17, 1999	May 28, 2002
58 FR 40591, July 29, 1993	Nov. 17, 1999	May 28, 2002
65 FR 61778, Oct. 17, 2000	Not Yet Adopted	

SUBPART VVV
40CFR60.740-748

STANDARDS OF PERFORMANCE FOR POLYMERIC COATING OF SUPPORTING SUBSTRATES

FR Citation	**Adoption Date**	**Delegation Date**
54 FR 37551, Sept. 11, 1989	May 23, 2007	January 3, 2008

SUBPART WWW STANDARDS OF PERFORMANCE FOR MUNICIPAL SOLID WASTE LANDFILLS
40CFR60.750-759

FR Citation	Adoption Date	Delegation Date
61 FR 9919, Mar. 12, 1996	Aug. 13, 1997	June 24, 1998
63 FR 32750, June 16, 1998	Not Yet Adopted	
64 FR 9262, Feb. 24, 1999	Not Yet Adopted	
65 FR 18908, Apr. 10, 2000	Not Yet Adopted	
65 FR 61778, Oct. 17, 2000	Not Yet Adopted	
71 FR 55127, Sept. 21, 2006	Not Yet Adopted	

SUBPART AAAA STANDARDS OF PERFORMANCE FOR SMALL MUNICIPAL WASTE COMBUSTION UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER AUGUST 30, 1999 OR FOR WHICH MODIFICATION OR RECONSTRUCTION IS COMMENCED AFTER JUNE 6, 2001
40CFR60.1000-1465

FR Citation	Adoption Date	Delegation Date
65 FR 76355, Dec. 6, 2000	June 20, 2007	January 3, 2008

SUBPART CCCC STANDARDS OF PERFORMANCE FOR COMMERCIAL AND INDUSTRIAL SOLID WASTE INCINERATION UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER NOVEMBER 30, 1999 OR FOR WHICH MODIFICATION OR RECONSTRUCTION IS COMMENCED ON OR AFTER JUNE 2, 2001
40CFR60.2000-2265

FR Citation	Adoption Date	Delegation Date
65 FR 75350, Dec. 1, 2000	June 20, 2007	January 3, 2008
66 FR 16606, Mar. 27, 2001	June 20, 2007	January 3, 2008
70 FR 55580, Sept. 22, 2005	June 20, 2007	January 3, 2008

SUBPART EEEE STANDARDS OF PERFORMANCE FOR OTHER SOLID WASTE INCINERATION UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER DECEMBER 9, 2004, OR FOR WHICH MODIFICATION OR RECONSTRUCTION IS COMMENCED ON OR AFTER JUNE 16, 2006
40CFR60.2880-2977

FR Citation	Adoption Date	Delegation Date
70 FR 74892, Dec. 16, 2005	June 20, 2007	January 3, 2008

SUBPART KKKK STANDARDS OF PERFORMANCE FOR NEW STATIONARY COMBUSTION TURBINES
40CFR60.4300-4420

FR Citation	Adoption Date	Delegation Date
71 FR 38497, July 6, 2006	*(date of adoption)*	

IT IS FURTHER RESOLVED AND ORDERED that readoption, by reference, of federal NSPS Subpart GG and adoption, by reference, of federal NSPS Subpart KKKK to Regulation X shall take effect and be in force on the date of delegation of enforcement authority to the Air Pollution Control District by the United States Environmental Protection Agency.

PASSED AND ADOPTED by the Air Pollution Control Board of the San Diego County Air Pollution Control District, State of California, this **25th** day of **February**, 2009, by the following votes:

AYES: Cox, Jacob, Slater-Price, Roberts, Horn

APPROVED AS TO FORM AND LEGALITY
COUNTY COUNSEL

BY ______ SENIOR DEPUTY

STATE OF CALIFORNIA)
County of San Diego) SS

I hereby certify that the foregoing is a full, true and correct copy of the Original Resolution entered in the Minutes of the Air Pollution Control Board.

THOMAS J. PASTUSZKA
Clerk of the Air Pollution Control Board

By: ______________________________
Catherine Santos, Deputy

Resolution No. 09-032
Meeting date: 2/25/09 (AP1)

ATTACHMENT B

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

PROPOSED AMENDMENT TO REGULATION X

CHANGE COPY

Proposed amendment to Regulation X is to read as follows:

REGULATION X. STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (NSPS) (Rev. Effective *(date of adoption)* ~~March 24, 2008)~~

The provisions of Part 60, Chapter I, Title 40, of the Code of Federal Regulations, (40 CFR 60), applicable to the subparts listed in this Regulation are hereby adopted by reference on the date shown and made part of the Air Pollution Control District Rules and Regulations. Whenever any source is subject to more than one rule, regulation, provision, or requirement relating to the control of any air contaminant, in cases of conflict or duplication the most stringent rule, regulation, provision, or requirement shall apply.

All new sources of air pollution and all modified or reconstructed sources of air pollution shall comply with the applicable standards, criteria, and requirements set forth herein. For the purpose of this Regulation, the word "Administrator" as used in 40 CFR 60 shall mean the Air Pollution Control Officer of the San Diego County Air Pollution Control District, except that the Air Pollution Control Officer shall not be empowered to approve alternate test methods, alternate standards or work practices. Other deviations, if any, from the provisions of 40 CFR 60 which are adopted by the Air Pollution Control Board are noted in the reference to the affected Subpart.

The U.S. Environmental Protection Agency (EPA) retains concurrent enforcement authority for these standards pursuant to Section 113 of the federal Clean Air Act, as amended, if the EPA Administrator desires to exercise it, including those not yet adopted by the Air Pollution Control District.

The addition of federal Subparts by reference to Regulation X shall take effect and be in force on the date of delegation of enforcement authority to the San Diego County Air Pollution Control District by EPA.

SUBPART D
40CFR60.40-46

STANDARDS OF PERFORMANCE FOR FOSSIL-FUEL-FIRED STEAM GENERATORS FOR WHICH CONSTRUCTION IS COMMENCED AFTER AUGUST 17, 1971

FR Citation	**Adoption Date**	**Delegation Date**
39 FR 20791, June 14, 1974	October 17, 2001	January 3, 2008
40 FR 2803, Jan. 16, 1975	October 17, 2001	January 3, 2008
40 FR 46256, Oct. 6, 1975	October 17, 2001	January 3, 2008

SUBPART D continued

FR Citation	Adoption Date	Delegation Date
41 FR 51398, Nov. 22, 1976	October 17, 2001	January 3, 2008
42 FR 37936, July 25, 1977	October 17, 2001	January 3, 2008
42 FR 61537, Dec. 5, 1977	October 17, 2001	January 3, 2008
43 FR 9278, Mar. 7, 1978	October 17, 2001	January 3, 2008
44 FR 33612, June 17, 1979	October 17, 2001	January 3, 2008
44 FR 76787, Dec. 28, 1979	October 17, 2001	January 3, 2008
45 FR 36077, May 29, 1980	October 17, 2001	January 3, 2008
45 FR 47146, July 14, 1980	October 17, 2001	January 3, 2008
46 FR 57498, Nov. 24, 1981	October 17, 2001	January 3, 2008
48 FR 3736, Jan. 27, 1983	October 17, 2001	January 3, 2008
51 FR 42797, Nov. 25, 1986	October 17, 2001	January 3, 2008
52 FR 28954, Aug. 4, 1987	October 17, 2001	January 3, 2008
54 FR 6662, Feb. 14, 1989	October 17, 2001	January 3, 2008
54 FR 21344, May 17, 1989	October 17, 2001	January 3, 2008
55 FR 5212, Feb. 14, 1990	October 17, 2001	January 3, 2008
61 FR 49976, Sept. 24, 1996	October 17, 2001	January 3, 2008
65 FR 61752, Oct. 17, 2000	Not Yet Adopted	
72 FR 32717, June 13, 2007	Not Yet Adopted	

SUBPART Da
40CFR60.40a-49a

STANDARDS OF PERFORMANCE FOR ELECTRIC UTILITY STEAM GENERATING UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER SEPTEMBER 18, 1978

FR Citation	Adoption Date	Delegation Date
44 FR 33613, June 11, 1979	October 17, 2001	January 3, 2008
48 F4 3737, Jan. 27, 1983	October 17, 2001	January 3, 2008
54 FR 6663, Feb. 14, 1989	October 17, 2001	January 3, 2008
54 FR 21344, May 17, 1989	October 17, 2001	January 3, 2008
55 FR 5212, Feb. 14, 1990	October 17, 2001	January 3, 2008
55 FR 18876, May 7, 1990	October 17, 2001	January 3, 2008
63 FR 49453, Sept. 16, 1998	October 17, 2001	January 3, 2008
64 FR 7464, Feb. 12, 1999	October 17, 2001	January 3, 2008
65 FR 61752, Oct. 17, 2000	October 17, 2001	January 3, 2008
66 FR 18551, April 10, 2001	October 17, 2001	January 3, 2008
66 FR 31178, June 11, 2001	October 17, 2001	January 3, 2008
66 FR 42610, Aug. 14, 2001	Not Yet Adopted	
70 FR 28653, May 18, 2005	Not Yet Adopted	
70 FR 51268, Aug. 30, 2005	Not Yet Adopted	
71 FR 9876, Feb. 27, 2006	Not Yet Adopted	
71 FR 33399, June 9, 2006	Not Yet Adopted	
72 FR 32722, June 13, 2007	Not Yet Adopted	

SUBPART Db
40CFR60.40b-49b

STANDARDS OF PERFORMANCE FOR INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

FR Citation	Adoption Date	Delegation Date
51 FR 42768, Nov. 25, 1986	April 25, 2001	January 3, 2008
52 FR 47842, Dec. 16, 1987	April 25, 2001	January 3, 2008
54 FR 51824, Dec. 18, 1989	April 25, 2001	January 3, 2008
54 FR 51819, Dec. 18, 1989	April 25, 2001	January 3, 2008
55 FR 5212, Feb. 14, 1990	April 25, 2001	January 3, 2008

SUBPART Db continued

FR Citation	Adoption Date	Delegation Date
55 FR 18876, May 7, 1990	April 25, 2001	January 3, 2008
60 FR 28062, May 30, 1995	April 25, 2001	January 3, 2008
61 FR 14031, Mar. 29, 1996	April 25, 2001	January 3, 2008
62 FR 52641, Oct. 8, 1997	April 25, 2001	January 3, 2008
63 FR 49454, Sept. 16, 1998	April 25, 2001	January 3, 2008
64 FR 7464, Feb. 12, 1999	April 25, 2001	January 3, 2008
65 FR 13243, Mar. 13, 2000	April 25, 2001	January 3, 2008
65 FR 61752, Oct. 17, 2000	Not Yet Adopted	
66 FR 18553, April 10, 2001	Not Yet Adopted	
66 FR 42610, Aug. 14, 2001	Not Yet Adopted	
66 FR 49834, Oct. 1, 2001	Not Yet Adopted	
69 FR 40773, July 7, 2004	Not Yet Adopted	
71 FR 9881, Feb. 27, 2006	Not Yet Adopted	
71 FR 33400, June 9, 2006	Not Yet Adopted	
72 FR 32742, June 13, 2007	Not Yet Adopted	

SUBPART Dc
40CFR60.40c-48c

STANDARDS OF PERFORMANCE FOR SMALL INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

FR Citation	Adoption Date	Delegation Date
55 FR 37683, Sept. 12, 1990	Aug. 13, 1997	June 24, 1998
61 FR 20736, May 8, 1996	Aug. 13, 1997	June 24, 1998
64 FR 7465, Feb. 12, 1999	Not Yet Adopted	
65 FR 61752, Oct. 17, 2000	Not Yet Adopted	
71 FR 9884, Feb. 27, 2006	Not Yet Adopted	
72 FR 32759, June 13, 2007	Not Yet Adopted	

SUBPART Eb
40CFR60.50b-59b

STANDARDS OF PERFORMANCE FOR LARGE MUNICIPAL WASTE COMBUSTORS FOR WHICH CONSTRUCTION IS COMMENCED AFTER SEPTEMBER 20, 1994 OR FOR WHICH MODIFCATION OR RECONSTRUCTION COMMENCED AFTER JUNE 19, 1996

FR Citation	Adoption Date	Delegation Date
60 FR 65419, Dec. 19, 1995	June 20, 2007	January 3, 2008
62 FR 45120, Aug. 25, 1997	June 20, 2007	January 3, 2008
62 FR 45125, Aug. 25, 1997	June 20, 2007	January 3, 2008
65 FR 61753, Oct. 17, 2000	June 20, 2007	January 3, 2008
66 FR 36476, July 12, 2001	June 20, 2007	January 3, 2008
66 FR 57827, Nov. 16, 2001	June 20, 2007	January 3, 2008
71 FR 27335, May 10, 2006	June 20, 2007	January 3, 2008

SUBPART Ec
40CFR60.50c-58c

STANDARDS OF PERFORMANCE FOR HOSPITAL/MEDICAL/ INFECTIOUS WASTE INCINERATORS FOR WHICH CONSTRUCTION IS COMMENCED AFTER JUNE 20, 1996

FR Citation	Adoption Date	Delegation Date
62 FR 48382, Sept. 15, 1997	June 20, 2007	January 3, 2008
65 FR 61753, Oct. 17, 2000	June 20, 2007	January 3, 2008

SUBPART K
40CFR60.110-113

STANDARDS OF PERFORMANCE FOR STORAGE VESSELS FOR PETROLEUM LIQUIDS FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JUNE 11, 1973, AND PRIOR TO MAY 19, 1978

FR Citation	Adoption Date	Delegation Date
39 FR 9317, March 8, 1974	June 20, 2007	January 3, 2008
39 FR 13776, April 17, 1974	June 20, 2007	January 3, 2008
39 FR 20794, June 14, 1974	June 20, 2007	January 3, 2008
42 FR 37937, July 25, 1977	June 20, 2007	January 3, 2008
45 FR 23379, April 4, 1980	June 20, 2007	January 3, 2008
48 FR 3737, Jan. 27, 1983	June 20, 2007	January 3, 2008
52 FR 11429, April 8, 1987	June 20, 2007	January 3, 2008
65 FR 61755, Oct. 17, 2000	June 20, 2007	January 3, 2008

SUBPART Ka
40CFR60.110a-115a

STANDARDS OF PERFORMANCE FOR STORAGE VESSELS FOR PETROLEUM LIQUIDS FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER May 18, 1978, AND PRIOR TO July 23, 1984

FR Citation	Adoption Date	Delegation Date
45 FR 23379, April 4, 1980	June 20, 2007	January 3, 2008
45 FR 83229, Dec. 18,1980	June 20, 2007	January 3, 2008
48 FR 3737, Jan. 27, 1983	June 20, 2007	January 3, 2008
52 FR 11429, April 8, 1987	June 20, 2007	January 3, 2008
65 FR 61756, Oct. 17, 2000	June 20, 2007	January 3, 2008
65 FR 78275, Dec. 14, 2000	June 20, 2007	January 3, 2008

SUBPART Kb
40CFR60.110b-117b

STANDARDS OF PERFORMANCE FOR VOLATILE ORGANIC LIQUID STORAGE VESSELS (INCLUDING PETROLEUM LIQUID STORAGE VESSELS) FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JULY 23, 1984

FR Citation	Adoption Date	Delegation Date
52 FR 11429, April 8, 1987	June 20, 2007	January 3, 2008
52 FR 22780, June 16, 1987	June 20, 2007	January 3, 2008
54 FR 32973, Aug. 11, 1989	June 20, 2007	January 3, 2008
62 FR 52641, Oct. 8, 1997	June 20, 2007	January 3, 2008
65 FR 61756, Oct. 17, 2000	June 20, 2007	January 3, 2008
65 FR 78275, Dec. 14, 2000	June 20, 2007	January 3, 2008
68 FR 59332, Oct. 15, 2003	June 20, 2007	January 3, 2008

SUBPART GG
40CFR60.330-335

STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES

FR Citation	Adoption Date	Delegation Date
44 FR 52798, Sept. 10, 1979	October 17, 2001	January 3, 2008
47 FR 3770, Jan. 27, 1982	October 17, 2001	January 3, 2008
52 FR 42434, Nov. 5, 1987	October 17, 2001	January 3, 2008
54 FR 6675 Feb. 14, 1989	October 17, 2001	January 3, 2008
54 FR 27016, June 27, 1989	October 17, 2001	January 3, 2008
65 FR 61759, Oct. 17, 2000	*(date of adoption)*	
69 FR 41359, July 8, 2004	*(date of adoption)*	
71 FR 9458, Feb. 24, 2006	*(date of adoption)*	

SUBPART AAA
40CFR60.530-539b

STANDARDS OF PERFORMANCE FOR NEW RESIDENTIAL WOOD HEATERS

FR Citation	Adoption Date	Delegation Date
53 FR 5873, Feb. 26, 1988	April 12, 2000	January 3, 2008
53 FR 12009, April 12, 1988	April 12, 2000	January 3, 2008
53 FR 14889, April 26, 1988	April 12, 2000	January 3, 2008
57 FR 5328, Feb. 13, 1992	April 12, 2000	January 3, 2008
60 FR 33925, June 29, 1995	April 12, 2000	January 3, 2008
63 FR 64874, Nov. 24, 1998	April 12, 2000	January 3, 2008
64 FR 7466, Feb. 12, 1999	April 12, 2000	January 3, 2008
65 FR 61763, Oct. 17, 2000	Not Yet Adopted	

SUBPART OOO
40CFR60.670-676

STANDARDS OF PERFORMANCE FOR NONMETALLIC MINERAL PROCESSING PLANTS

FR Citation	Adoption Date	Delegation Date
50 FR 31328, Aug. 1, 1985	April 28, 1999	May 28, 2002
51 FR 31337, Aug. 1, 1985	Not Yet Adopted	
54 FR 6680, Feb. 14, 1989	Not Yet Adopted	
62 FR 31351, June 9, 1997	April 28, 1999	May 28, 2002
65 FR 61778, Oct. 17, 2000	Not Yet Adopted	

SUBPART UUU
40CFR60.730-737

STANDARDS OF PERFORMANCE FOR CALCINERS AND DRYERS IN MINERAL INDUSTRIES

FR Citation	Adoption Date	Delegation Date
57 FR 44503, Sept. 28, 1992	Nov. 17, 1999	May 28, 2002
58 FR 40591, July 29, 1993	Nov. 17, 1999	May 28, 2002
65 FR 61778, Oct. 17, 2000	Not Yet Adopted	

SUBPART VVV
40CFR60.740-748

STANDARDS OF PERFORMANCE FOR POLYMERIC COATING OF SUPPORTING SUBSTRATES

FR Citation	Adoption Date	Delegation Date
54 FR 37551, Sept. 11, 1989	May 23, 2007	January 3, 2008

SUBPART WWW
40CFR60.750-759

STANDARDS OF PERFORMANCE FOR MUNICIPAL SOLID WASTE LANDFILLS

FR Citation	Adoption Date	Delegation Date
61 FR 9919, Mar. 12, 1996	Aug. 13, 1997	June 24, 1998
63 FR 32750, June 16, 1998	Not Yet Adopted	
64 FR 9262, Feb. 24, 1999	Not Yet Adopted	
65 FR 18908, Apr. 10, 2000	Not Yet Adopted	
65 FR 61778, Oct. 17, 2000	Not Yet Adopted	
71 FR 55127, Sept. 21, 2006	Not Yet Adopted	

SUBPART AAAA
40CFR60.1000-1465

STANDARDS OF PERFORMANCE FOR SMALL MUNICIPAL WASTE COMBUSTION UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER AUGUST 30, 1999 OR FOR WHICH MODIFICATION OR RECONSTRUCTION IS COMMENCED AFTER JUNE 6, 2001

FR Citation	Adoption Date	Delegation Date
65 FR 76355, Dec. 6, 2000	June 20, 2007	January 3, 2008

SUBPART CCCC
40CFR60.2000-2265

STANDARDS OF PERFORMANCE FOR COMMERCIAL AND INDUSTRIAL SOLID WASTE INCINERATION UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER NOVEMBER 30, 1999 OR FOR WHICH MODIFICATION OR RECONSTRUCTION IS COMMENCED ON OR AFTER JUNE 2, 2001

FR Citation	Adoption Date	Delegation Date
65 FR 75350, Dec. 1, 2000	June 20, 2007	January 3, 2008
66 FR 16606, Mar. 27, 2001	June 20, 2007	January 3, 2008
70 FR 55580, Sept. 22, 2005	June 20, 2007	January 3, 2008

SUBPART EEEE
40CFR60.2880-2977

STANDARDS OF PERFORMANCE FOR OTHER SOLID WASTE INCINERATION UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER DECEMBER 9, 2004, OR FOR WHICH MODIFICATION OR RECONSTRUCTION IS COMMENCED ON OR AFTER JUNE 16, 2006

FR Citation	Adoption Date	Delegation Date
70 FR 74892, Dec. 16, 2005	June 20, 2007	January 3, 2008

<u>SUBPART KKKK</u>
<u>40CFR60.4300-4420</u>

<u>STANDARDS OF PERFORMANCE FOR NEW STATIONARY COMBUSTION TURBINES</u>

FR Citation	Adoption Date	Delegation Date
<u>71 FR 38497, July 6, 2006</u>	<u>*(date of adoption)*</u>	

ATTACHMENT C

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart GG—Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000]

§ 60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) *Simple cycle gas turbine* means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

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

(d) *Combined cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) *Emergency gas turbine* means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) *Ice fog* means an atmospheric suspension of highly reflective ice crystals.

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

(h) *Efficiency* means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) *Peak load* means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) *Base load* means the load level at which a gas turbine is normally operated.

(k) *Fire-fighting turbine* means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) *Turbines employed in oil/gas production or oil/gas transportation* means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A *Metropolitan Statistical Area* or *MSA* as defined by the Department of Commerce.

(n) *Offshore platform gas turbines* means any stationary gas turbine located on a platform in an ocean.

(o) *Garrison facility* means any permanent military installation.

(p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) *Electric utility stationary gas turbine* means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) *Emergency fuel* is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) *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.

(t) *Excess emissions* means a specified averaging period over which either:

(1) The NO_X emissions are higher than the applicable emission limit in §60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; 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.

(u) *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. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

(v) *Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas 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.

(w) *Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) *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. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) *Unit operating day* means a 24-hour period between 12:00 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.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150 \frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NO_X allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO_X emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

Fuel-bound nitrogen (percent by weight)	**F (NO_X percent by volume)**
$N \leq .015$	0
$0.015 < N \leq 0.1$	0.04 (N)
$0.1 < N \leq 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_X emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979,Federal Register(44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by §60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004]

§ 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_X emissions shall 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.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F–14a or F–14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, *i.e.* , the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO_X) and a percent O_2 basis for oxygen; or

(ii) On a ppm at 15 percent O_2 basis; or

(iii) On a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O_2).

(2) As specified in §60.13(e)(2), during each full unit operating hour, each 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 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 to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in §60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NO_X and diluent, the data acquisition and handling system must calculate and record the hourly NO_X emissions in the units of the applicable NO_X emission standard under §60.332(a), *i.e.*, percent NO_X by volume, dry basis, corrected to 15 percent O_2 and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(iii) If the owner or operator has installed a NO_XCEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_X emissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NO_X emission limit under §60.332, that approved procedure may continue to be used.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO_X emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO_XCEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_X emissions, may, but is not required to, elect to use a NO_XCEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NO_X emissions may, but is not required to, perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO_X formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(3) For any turbine that uses SCR to reduce NO_X emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in §75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges. The owner or operator 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. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in §75.19 of this chapter or the NO_X emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in §75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (*i.e.* , if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. 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.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *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). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) 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 (i)(3)(i) and (i)(3)(ii) 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 §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) 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 (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), 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 between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(*1*) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*2*) of this section.

(*2*) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*3*) of this section.

(*3*) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) 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:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (*i.e.* , the maximum total sulfur content of natural gas as defined in §60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) 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 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

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

(A) An excess emission shall be any unit operating hour for which the 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 §60.332, 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 shall also be considered an excess emission.

(B) A period of monitor downtime shall be 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.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) 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 that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NO_X and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NO_X concentration" is the arithmetic average of the average NO_X concentration measured by the CEMS for a given hour (corrected to 15 percent O_2 and, if required under §60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_X concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_X concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(A) An excess emission shall be 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.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) 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 gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall 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 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) 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 shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) *Ice fog.* Each period during which an exemption provided in §60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) *Emergency fuel.* Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

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

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41360, July 8, 2004; 71 FR 9457, Feb. 24, 2006]

§ 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in §60.8, using either

(1) EPA Method 20,

(2) ASTM D6522–00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO_X and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall 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.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

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

(A) [Reserved]

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

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

(A) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 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 3 points shall be located along the measurement line that exhibited the highest average normalized NO_X concentration during the stratification test; or

(B) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{X_o}) corrected to 15 percent O_2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is

optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$NO_X=(NO_{Xo})(P_r/P_o)^{0.5}\ e19\ (Ho-0.00633)(288°K/T_a)^{1.53}$$

Where:

NO_X= emission concentration of NO_X at 15 percent O_2 and ISO standard ambient conditions, ppm by volume, dry basis,

NO_{Xo}= mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O_2,

P_r= reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

P_o= observed combustor inlet absolute pressure at test, mm Hg,

H_o= observed humidity of ambient air, g H_2O/g air,

e = transcendental constant, 2.718, and

T_a= ambient temperature, °K.

(2) The 3-run performance test required by §60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in §60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_X emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_X emission limit in §60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00 (incorporated by reference, see §60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 NO_X emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_XCEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator elects under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters shall 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 §60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597–94 (Reapproved 1999), D6366–99, D4629–02, D5762–02 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, ASTM D1072–80, 90 (Reapproved 1994); D3246–81, 92, 96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see §60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

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

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004, as amended at 71 FR 9458, Feb. 24, 2006]

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

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

Introduction

§ 60.4300 What is the purpose of this subpart?

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

Applicability

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

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

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

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

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

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

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

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

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

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

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

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

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

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

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

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

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

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

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

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

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

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

General Compliance Requirements

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

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

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

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

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

Monitoring

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

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

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

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

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

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

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

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

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

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

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

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

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

§ 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_XCEMS is chosen:

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

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

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

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

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

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

For purposes of identifying excess emissions:

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

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

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

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

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

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

(1) For simple-cycle operation:

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

Where:

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

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

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

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

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

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

Where:

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

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

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

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

Where:

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

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 10_6= conversion from Btu/h to MW.

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

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

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

Where:

E = NO_X emission rate in lb/MWh,

$(NO_X)_m$= NO_X emission rate in lb/h,

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

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

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

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

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

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

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

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

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

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

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Reporting

§ 60.4375   What reports must I submit?

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

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

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

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

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

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

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

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

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

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

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

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

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

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

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

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

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

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

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

(a) If you operate an emergency combustion turbine, you are exempt from the NO_X limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_X limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 When must I submit my reports?

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

Performance Tests

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

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

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

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

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

Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/dscf-ppm

$(NO_X)_c$ = average NO_X concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

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

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

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

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

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

(A) [Reserved], or

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

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

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

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

(C) For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

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

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

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(2) Measure the SO_2 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_2 emission rate:

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

Where:

E = SO_2 emission rate, in lb/MWh

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

$(SO_2)_c$ = average SO_2 concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

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

(3) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

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

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

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

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

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

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

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

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

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

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

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

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

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

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

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

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

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

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

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

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

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

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

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

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

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

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).

New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O_2or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

ATTACHMENT D

AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

ADOPTION BY REFERENCE OF
TITLE 40 CODE OF FEDERAL REGULATION (CFR) PART 60
NEW SOURCE PERFORMANCE STANDARDS (NSPS):

SUBPART GG – STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES

SUBPART KKKK – STANDARDS OF PERFORMANCE FOR COMBUSTION TURBINES

WORKSHOP REPORT

A workshop notice was mailed to 35 facilities in San Diego County that are subject to Title 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines or Subpart KKKK – Standards of Performance for Combustion Turbines. Notices were also mailed to all Economic Development Corporations and Chambers of Commerce in San Diego County, the U.S. Environmental Protection Agency, the California Air Resources Board, and other interested parties.

The workshop was held on November 3, 2008, and 11 members of the public attended. Comments were received during the workshop regarding adoption by reference of the two above listed NSPSs.

The comments and District responses are as follows:

1. WORKSHOP COMMENT

NSPS Subpart KKKK allows the performance testing frequency for nitrogen oxide (NO_x) emissions to be reduced to once every two years if performance test results are equal to or less than 75% of the applicable NO_x emission limit. Is this the applicable emission limit as required in the NSPS or the NO_x limit as stated on the Air Pollution Control District (District) permit for the turbine?

DISTRICT RESPONSE

NSPS Subpart KKKK allows the frequency of source testing to be reduced to once every two years if the performance test results are equal to or less than 75% of the applicable NO_x emission limit as required in the NSPS. Even if the NO_x emission limit as required in the turbine's permit is less than the NSPS limit, this standard still refers to the applicable NSPS emission limit. However, District Rule 69.3.1 requires an annual performance test unless otherwise specified by the Air Pollution Control Officer. The District does not currently plan to reduce performance testing frequency as allowed by the NSPS.

2. <u>WORKSHOP COMMENT</u>

How often must periodic fuel testing for sulfur content be conducted?

<u>DISTRICT RESPONSE</u>

An owner or operator may elect not to monitor total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 0.06 pounds of sulfur dioxide (SO_2) per million British thermal units heat input. This can be demonstrated by verifying that the maximum total sulfur content for fuel oil is 0.05 weight percent or less, or for natural gas is 20 grains of sulfur or less per 100 standard cubic feet for natural gas. If an operator/owner elects not to demonstrate that sulfur content is below the above listed thresholds, then for gaseous fuel, the sulfur content of the fuel must be determined and recorded once per unit operating day. For fuel oil, use one of the sampling options and associated sampling frequencies described in Appendix D of 40 CFR Part 75.

3. <u>WORKSHOP COMMENT</u>

Is the 30-day rolling average for combined cycle or combined heat and power turbines used in determining excess NO_x emissions for turbines based on the Subpart KKKK limit or the NO_x limit as stated on the District permit for the turbine?

<u>DISTRICT RESPONSE</u>

Excess emissions are identified relative to the Subpart KKKK applicable emission limit and would not reflect lower emission limits as stated on the District permit.

4. <u>WORKSHOP COMMENT</u>

Is District Rule 69.3.1 more stringent than Subpart KKKK for new turbines? Are facilities responsible for compliance with both Rule 69.3.1 and NSPS Subpart KKKK or Subpart GG?

<u>DISTRICT RESPONSE</u>

District Rule 69.3.1 satisfies California Clean Air Act requirements and, in general, is more stringent than Subpart KKKK for new turbines. Facilities are responsible for complying with both Rule 69.3.1 and NSPS Subpart KKKK or Subpart GG, as applicable.

RR:CB:jlm
11/07/08