WEST VIRGINIA
SECRETARY OF STATE
NATALIE E. TENNANT
ADMINISTRATIVE LAW DIVISION

Form #1

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2009 JUN 10 AM 11: 21

OFFICE WEST VIRGINIA
SECRETARY OF STATE

NOTICE OF A PUBLIC HEARING ON A PROPOSED RULE

AGENCY: WV Department of Environmental Protection - Division of Air Quality TITLE NUMBER: 45

RULE TYPE: Legislative CITE AUTHORITY: W. Va. Code §22-5-4

AMENDMENT TO AN EXISTING RULE: YES [X] NO [ ]

IF YES, SERIES NUMBER OF RULE BEING AMENDED: 45CSR33

TITLE OF RULE BEING AMENDED: Acid Rain Provisions and Permits

IF NO, SERIES NUMBER OF RULE BEING PROPOSED:

TITLE OF RULE BEING PROPOSED:

DATE OF PUBLIC HEARING: July 13, 2009 TIME: 6:00 p.m.

LOCATION OF PUBLIC HEARING: WV Department of Environmental Protection
Dolly Sods Conference Room
601 57th Street, S.E.
Charleston, WV 25304

COMMENTS LIMITED TO: ORAL [ ] WRITTEN [ ] BOTH [X]

DATE WRITTEN COMMENT PERIOD ENDS: July 13, 2009 TIME: Close of Hearing

WRITTEN COMMENTS MAY BE MAILED TO:
Kathy Cosco, Public Information Office
WV Department of Environmental Protection
601 57th Street, S.E.
Charleston, WV 25304

The Department requests that persons wishing to make comments at the hearing make an effort to submit written comments in order to facilitate the review of these comments.

The issues to be heard shall be limited to the proposed rule.

ATTACH A **BRIEF** SUMMARY OF YOUR PROPOSAL

Authorized Signature

DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF AIR QUALITY

BRIEFING DOCUMENT

Rule Title: 45CSR33 - "Acid Rain Provisions and Permits"

A. AUTHORITY: W.Va. Code §22-5-4

B. SUMMARY OF RULE:

This rule establishes and adopts the general provisions and operating permit program requirements for affected sources under the Acid Rain Program promulgated by the United States Environmental Protection Agency (U.S. EPA) under Title IV of the Clean Air Act, as amended (CAA). The rule also adopts associated appendices, reference methods, performance specifications and other test methods which are appended to these provisions. Under the Acid Rain Program and 45CSR33, no person may construct, modify, or operate or cause to be constructed, modified, or operated, an Acid Rain source in violation of 40 CFR Parts 72 through 77.

Title IV of the CAA requires each state to implement an operating permit system conforming to Title IV and Title V of the CAA, as amended. 45CSR33 incorporates by reference the federal counterpart regulation 40 CFR Parts 72 through 77. U.S. EPA approved West Virginia's Acid Rain Program with its approval of the state's Title V Operating Permit Program on October 3, 2001.

This revised rule incorporates by reference the following revisions to 40 CFR Parts 72 through 77 promulgated as of June 1, 2009: Air Pollution Control, Transport of Emissions of NO_X and SO_2; Amendments to Monitoring Provisions; Revisions to Acid Rain Program Rules, and Revisions to the Continuous Monitoring Rule for the Acid Rain Program.

C. STATEMENT OF CIRCUMSTANCES WHICH REQUIRE RULE:

Promulgation of this rule will enable the Department of Environmental Protection, Division of Air Quality (DAQ) to continue to be the primary enforcement authority for the Acid Rain Program promulgated under 40 CFR Parts 72 through 77 by U.S. EPA as of June 1, 2009. Promulgation of this rule by the Legislature is necessary for the State to fulfill its responsibilities under the CAA, as amended. Revisions to the rule include annual incorporation by reference rule updates.

D. FEDERAL COUNTERPART REGULATIONS - INCORPORATION BY REFERENCE/DETERMINATION OF STRINGENCY:

A federal counterpart to this proposed rule exists. In accordance with the Secretary's recommendation, and with limited exception, the Division of Air Quality proposes that the rule incorporate by reference the federal counterparts. Because the proposed rule incorporates by reference the federal counterpart, no determination of stringency is required.

E. CONSTITUTIONAL TAKINGS DETERMINATION:

In accordance with W.Va. Code §§22-1A-1 and 3(c), the Secretary has determined that this rule will not result in taking of private property within the meaning of the Constitutions of West Virginia and the United States of America.

F. CONSULTATION WITH THE ENVIRONMENTAL PROTECTION ADVISORY COUNCIL:

At its June 3, 2009 meeting, the Environmental Protection Advisory Council reviewed and discussed this proposed rule. The Council's comments are contained in the attached minutes.

West Virginia Department of Environmental Protection

ADVISORY COUNCIL MEETING MINUTES

Wednesday, June 3, 2009
601 57th Street, SE, Charleston, West Virginia
West Virginia Room – 3rd Floor

IN ATTENDANCE:

Members of the Council:

Lisa Dooley
Jackie Hallinan
Larry Harris
Karen Price
Bill Raney
Rick Roberts

DEP:

Raymond Franks II	General Counsel
Kristin Boggs	Associate General Counsel
Kathy Cosco	Chief Communications Officer
Tom Clarke	Director, Division of Mining & Reclamation
James Martin	Chief, Office of Oil & Gas
Robert Bates	Division of Water & Waste Management
Bill Brannon	Division of Water & Waste Management
Carroll Cather	Division of Water & Waste Management
Ellen Herndon	Division of Water & Waste Management
Jeff Knepper	Division of Water & Waste Management
Teresa Koon	Division of Water & Waste Management
Sudhir Patel	Division of Water & Waste Management
Yogesh Patel	Division of Water & Waste Management
Bill Timmermeyer	Division of Water & Waste Management
Ken Politan	Division of Mining & Reclamation
Jim Mason	Division of Air Quality

Others:

Don Garvin	Interested Citizen
Steve Hannah	Interested Citizen
Dave Yaussy	Interested Citizen

<u>OLD BUSINESS</u>:

Raymond Franks called the meeting to order at 1:45 p.m. Mr. Franks noted that two members of the Council had pointed out a minor discrepancy in the April minutes as circulated, and that for expediency's sake the error would be corrected following the meeting and the April and June minutes each moved for approval at the September meeting.

Mr. Franks provided to the Council information it had requested at the April meeting regarding ongoing projects in the Office of Abandoned Mine Lands and recruiting potential for environmental inspectors. The Council agreed to review the information and discuss it in more detail at the September meeting.

<u>NEW BUSINESS</u>:

Mr. Franks turned the meeting over to Kristin Boggs for presentation and discussion of the 2010 proposed Legislative Rules:

DIVISION OF WATER & WASTE MANAGEMENT – WATER RULES

47CSR10 – ***NPDES Rule***: Promulgated last in 2008. The proposed revisions reflect changes made to the Federal rule regarding Concentrated Animal Feeding Operations (CAFOs), which became effective in November 2008. EPA gave DEP two years to revise the State rules and start issuing permits. The revisions include a clarified definition of CAFO, a detailed explanation of the permitting process and the process for permit exemption, and an explanation of the required nutrient management plan. Technical revisions and corrections are made throughout.

47CSR26 – ***Water Pollution Control Permit Fee Schedules***: Promulgated last in 2000. The proposed revisions reflect the CAFO changes made in the NPDES Rule. The fees for CAFOs will be as follows: $300 for the initial application; $300 for permit renewal; $50 for permit modification; and $50 for the annual permit fee. Technical revisions and corrections are made throughout.

47CSR12 – ***Requirements re Groundwater Standards***: Promulgated last in 2002. The proposed revisions reflect updates and additions made to EPA's 2006 edition of the Drinking Water Standards & Health Advisories. Technical revisions and corrections are made throughout.

47CSR59 – ***Monitoring Well Rule***. Promulgated last in 1994. The proposed revisions add new language to incorporate "high" and "low" risk boreholes, experience requirements for those persons applying for monitoring well driller certificates, recertification and training requirements for monitoring well drillers, and definitions. Technical revisions and corrections are made throughout.

47CSR60 – ***Monitoring Well Design Standards***. Promulgated last in 1996. The proposed revisions bring this rule in conformance with the 47CSR59 *Monitoring Well Rule* definition changes, and "high" and "low" borehole requirements. Technical revisions and corrections are made throughout.

Division of Water & Waste Management – Waste Management Rules

33CSR1 – ***Solid Waste Management Rule***: Promulgated last in 2006. The proposed revisions include removing the requirement that free day tonnage count toward monthly/daily totals and clarifying the definition of pick-up truck. Technical revisions and corrections are made throughout.

33CSR20 – ***Hazardous Waste Management System***: Promulgated last in 2009. The proposed rule reflects the annual incorporation-by-reference (IBR) revisions made by DEP to its hazardous waste rule. The proposed revisions include changes to the academic laboratory waste provisions to allow alternative requirements for hazardous waste determination and accumulation of unwanted materials at labs owned by and affiliated with colleges and universities. Other proposed revisions are directed at the hazardous waste code 019 provisions, which expand the exclusion for sludges generated from the chemical conversion coating of aluminum using a zinc phosphating process. The F019 waste code exclusion only applies to the automobile or light truck manufacturing industry. This IBR specifically excludes two federal amendments that are currently undergoing reconsideration by the EPA, *i.e.*, revisions to the definition of solid waste and expansion of RCRA comparable fuel exclusion. Technical revisions and corrections are made throughout.

Mr. Franks asked whether the Council had any questions about the seven DWWM rules. Mr. Raney inquired about the impetus for the change in the monitoring well rules, since they have not been revised in several years. Ms. Boggs responded that the changes in the rules reflect changes in technology and practice over time. There were no further questions from the Council.

Office of Oil and Gas Rule

35CSR4 – ***Oil & Gas Wells and Other Wells***: Promulgated last in 2001. The proposed revisions include updating the permit fees to reflect the 2005 statutory change, clarifying general requirements for pit and impoundment construction, and adding a new section setting forth requirements for constructing pits and impoundments that exceed a certain size. Technical revisions and corrections are made throughout.

Mr. Franks asked whether the Council had any questions about the OOG rule. Dr. Harris expressed concern that the current statutory bond amount may not suffice given the larger pits associated with Marcellus wells. Mr. Martin explained that the bond is a performance bond, not designed to cover any specific area of the well operation. Dr. Harris than asked about protections for surface owners whose water supply is impaired from drilling operations, in response to which Mr. Martin pointed out the statutory and regulatory remedies. There were no further questions from the Council.

Division of Mining & Reclamation Rule

47CSR30 – ***Mining NPDES Rule***: Promulgated last in 2009. The proposed revisions include deleting the certification language for NPDES maps and decreasing from two years to one the raw mine drainage water quality data required for abandonment of a deep mine. Technical revisions and corrections are made throughout.

Mr. Franks asked whether the Council had any questions about the DMR rule. Ms. Dooley inquired whether the changes were substantive or merely technical. Ms. Boggs explained that although the changes appeared merely technical, they had real-world effects upon licensed professional engineers and surveyors, whom the rule required to swear to the contents of a NPDES map under penalty of perjury. Engineers and surveyors could not obtain insurance for such an oath, because they did not create the maps and were therefore subjecting themselves to criminal penalties for work that was not entirely within their control. There were no further questions from the Council.

DIVISION OF AIR QUALITY RULES

45CSR8 – ***Ambient Air Quality Standards***: Promulgated last in 2009. The proposed revisions include deletion of redundant measurement method language for lead and addition of new national primary and secondary ambient air quality standards for lead.

45CSR14 – ***Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration***: Promulgated last in 2009. The proposed revisions incorporate the New Source Review Program for Particulate Matter Less Than 2.5 Micrometers. Other miscellaneous revisions and corrections are also included, so that the rule comports with federal counterpart language.

45CSR16 – ***Standards of Performance for New Stationary Sources***: Promulgated last in 2009. The proposed rule reflects the annual IBR revisions to New Source Performance Standards, including Stationary Spark-Ignition Internal Combustion Engines, Fossil Fuel-Fired Steam Generators and Industrial-Commercial-Institutional Steam Generating Units, Stationary Combustion Turbines, Nonroad Spark Ignition Engines, Alternative Work Practice To Detect Leaks From Equipment, Petroleum Refineries and Performance Specification 16 for Predictive Emissions Monitoring Systems, Amendments to Testing and Monitoring Provisions, and Nonmetallic Mineral Processing Plants. The IBR exclusion for the vacated Clean Air Mercury Rule has been removed.

45CSR19 – ***Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution Which Cause or Contribute to Nonattainment***: Promulgated last in 2005. The proposed revisions incorporate the New Source Review Program for Particulate Matter Less Than 2.5 Micrometers, Reasonable Possibility in Recordkeeping, Ethanol Production Facilities, and 8-Hour Ozone National Ambient Air Quality Standard provisions. Other proposed revisions to the rule remove references to pollution control projects and clean units per the 2005 decision by the United State Court of Appeals for the District of Columbia Circuit that vacated the parallel federal provisions. Other miscellaneous revisions and/or corrections are also included, so that the rule comports with federal counterpart language.

45CSR25 – ***Control of Air Pollution from Hazardous Waste Treatment, Storage and Disposal Facilities***: Promulgated last in 2009. The proposed rule reflects the annual IBR revisions to the Hazardous Waste rule.

45CSR33 – ***Acid Rain Provisions and Permits***: Promulgated last in 2006. The proposed rule reflects the annual IBR revisions, including Air Pollution Control, Transport of Emissions of Nitrogen Oxide and Sulfur Dioxide; Amendments to Monitoring Provisions; Revisions to Acid Rain Program Rules, and Revisions to the Continuous Monitoring Rule for the Acid Rain Program.

45CSR34 – ***Emission Standards for Hazardous Air Pollutants***: Promulgated last in 2009. The proposed rule reflects the annual IBR revisions to the Hazardous Air Pollutant rule. Excluded from incorporation by reference are the national emission standards for hazardous air pollutants affecting non-major (area) sources of hazardous air pollutants for Iron and Steel Foundries, Plating and Polishing Operations, Ferroalloys Production Facilities, and Metal Fabrication and Finishing Source Categories.

Mr. Franks asked whether the Council had any questions about the seven DAQ Rules, and there were none.

On general comment, Dr. Harris inquired about water quality standards for mercury, citing a newspaper report that DEP supported less stringent standards based on data that State residents consume relatively fewer fish per capita. Mr. Clarke explained the factual context of the reported quote and the method by which EPA developed the point three (0.3) standard. With respect to the rules presentation, Dr. Harris suggested a return to the practice of providing Council with written summaries of the proposed rules, along with justifications for the proposed changes. The suggestion was well-received.

Mr. Franks then opened the floor to questions from the general public. Don Garvin, Legislative Coordinator for the West Virginia Environmental Council, inquired about acid rain standards, to which Mr. Mason responded that the State's standards with respect to acid rain derive from Title VI of the federal Clean Air Act.

Dr. Harris then asked whether the downtown in the energy market has caused any decrease in the number of permit applications to drill gas wells in the Marcellus Shale. Mr. Martin responded that the economy has had some effect on the number of permit applications overall, and that he could later provide Dr. Harris with more precise statistics.

Mr. Garvin complimented the Agency and the Office of Oil & Gas on finally requiring pits to be lined. Mr. Raney then thanked DEP staff for their hard work on the rules.

With no further comments forthcoming from the Council or public, Mr. Franks reminded everyone that the next meeting is scheduled for Wednesday, September 23, 2009. On motion from Mr. Raney, seconded by Mr. Roberts, Mr. Franks declared the meeting adjourned at 2:45 p.m.

APPENDIX B

FISCAL NOTE FOR PROPOSED RULES

Rule Title: 45CSR33 - "Acid Rain Provisions and Permits"

Type of Rule: ___X__ Legislative _____Interpretive _____Procedural

Agency: Division of Air Quality

Address: 601 57th Street SE

Charleston, WV 25304

Phone Number: 926-0475 Email: tammy.l.mowrer@wv.gov

Fiscal Note Summary

Summarize in a clear and concise manner what impact this measure will have on costs and revenues of state government.

No impact above that resulting from currently applicable federal emission standards.

Fiscal Note Detail

Show over-all effect in Item 1 and 2 and, in Item 3, give an explanation of Breakdown by fiscal year, including long-range effect.

FISCAL YEAR			
Effect of Proposal	2010 Increase/Decrease (use "-")	2011 Increase/Decrease (use "-")	Fiscal Year (Upon Full Implementation)
1. Estimated Total Cost	$ 0	$ 0	$ 0
Personal Services	0	0	0
Current Expenses	0	0	0
Repairs & Alterations	0	0	0
Assets	0	0	0
Equipment	0	0	0
Other	0	0	0
2. Estimated Total Revenues	0	0	0

Rule Title: 45CSR33 - "Acid Rain Provisions and Permits"

3. Explanation of above estimates (including long-range effect):
Please include any increase or decrease in fees in your estimated total revenues.

Costs anticipated to be incurred in the implementation of federal rules promulgated under 40 CFR Parts 72 through 77 as of June 1, 2009 are included in prior cost estimates prepared for state implementation of Title V of the Clean Air Act, as amended, under 45CSR30. Full Title V program approval was issued by the U.S. Environmental Protection Agency on November 19, 2001.

MEMORANDUM

Please identify any areas of vagueness, technical defects, reasons the proposed rule **would not** have a fiscal impact, and/or any special issues **not** captured elsewhere on this form.

Date: 6/4/09

Signature of Agency Head

FILED

2009 JUN 10 AM 11: 22

OFFICE WEST VIRGINIA
SECRETARY OF STATE

TITLE 45
LEGISLATIVE RULE
DEPARTMENT OF ENVIRONMENTAL PROTECTION
~~OFFICE OF~~ AIR QUALITY

SERIES 33
ACID RAIN PROVISIONS AND PERMITS

§45-33-1. General.

1.1. Scope. -- This rule establishes and adopts general provisions and the operating permit program requirements for affected sources and affected units under the Acid Rain Program promulgated by the United States Environmental Protection Agency under Title IV of the Clean Air Act, as amended (CAA). The Secretary hereby adopts these standards by reference. The Secretary also adopts associated reference methods, performance specifications and other test methods which are appended to these standards.

1.2. Authority. -- W. Va. Code §22-5-4.

1.3. Filing Date. -- ~~April 28, 2006~~.

1.4. Effective Date. -- ~~May 1, 2006~~.

1.5. Incorporation by Reference. -- Federal Counterpart Regulation. The Secretary has determined that a federal counterpart regulation exists, and in accordance with the Secretary's recommendation this rule incorporates by reference the following provisions: 40 CFR Part 72, "Permits Regulation"; 40 CFR Part 74, "Sulfur Dioxide Opt-Ins"; 40 CFR Part 75, "Continuous Emissions Monitoring"; 40 CFR Part 76, "Nitrogen Oxides Reduction Program"; and 40 CFR Part 77, "Excess Emissions"; effective ~~June 1, 2005~~ June 1, 2009.

1.6. Former Rules. -- This legislative rule amends 45CSR33 "Acid Rain Provisions and Permits" which was filed ~~April 21, 2003~~ April 28, 2006, and which became effective ~~June 1, 2003~~ May 1, 2006.

§45-33-2. Definitions.

2.1. "Administrator" means the Administrator of the United States Environmental Protection Agency.

2.2. "Clean Air Act" ("CAA") means 42 U.S.C. §7401 et seq.

2.3. "Permitting Authority" means the Secretary of the West Virginia Department of Environmental Protection.

2.4. "Secretary" means the Secretary of the Department of Environmental Protection or other person to whom the Secretary has delegated authority or duties pursuant to W. Va. Code §§22-1-6 or 22-1-8.

2.5. Other words and phrases used in this rule, unless otherwise indicated, will have the meaning ascribed to them in 40 CFR §72.2. Words and phrases not defined therein will have the meaning given to them in federal Clean Air Act.

§45-33-3. Requirements.

3.1. No person may construct, modify, or operate or cause to be constructed, modified, or operated an affected source which results or will result in a violation of this rule.

§45-33-4. Adoption of Standards.

4.1. The Secretary hereby adopts and

incorporates by reference the following provisions of the United States Environmental Protection Agency Acid Rain Program effective ~~June 1, 2005~~ June 1, 2009: 40 CFR Part 72, "Permits Regulation", including all Subparts and Appendices; 40 CFR Part 74, "Sulfur Dioxide Opt-Ins", including all Subparts; 40 CFR Part 75, "Continuous Emissions Monitoring", including all Subparts and Appendices; 40 CFR Part 76, "Nitrogen Oxides Emissions Reduction Program", including all Appendices; and 40 CFR Part 77, "Excess Emissions". These provisions are adopted for the purposes of implementing an acid rain program that meets the requirements of Title IV of the federal CAA, as amended.

§45-33-5. Inconsistency Between Rules.

5.1. The provisions of this rule must not be construed as exempting persons subject to this rule from compliance with any other provisions of the CAA, including the provisions of Title I of the CAA relating to applicable National Ambient Air Quality Standards, the State Implementation Plan, or any other rules of the West Virginia Department of Environmental Protection, except as expressly provided under Title IV of the CAA; provided however, that in the event of any inconsistency between the provisions of this rule and any provisions of 45CSR30, the provisions of this rule will take precedence and will govern the issuance, denial, revision, reopening, renewal, and appeal of the Acid Rain provision of an operating permit.

Federal Register

Friday,
April 28, 2006

Part IV

Environmental Protection Agency

40 CFR Parts 51, 52 et al.

Air Pollution Control—Transport of Emissions of Nitrogen Oxides (NO_X) and Sulfur Dioxide (SO_2); Final Rule

comply with such applicable requirements.

§ 52.2141 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

The owner or operator of each SO_2 source located within the State of South Carolina and for which requirements are set forth under the Federal CAIR SO_2 Trading Program in part 97 of this chapter must comply with such applicable requirements.

Subpart RR—Tennessee

■ 27. Subpart RR is amended by adding §§ 52.2240 and 52.2241 to read as follows:

§ 52.2240 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

The owner or operator of each NO_X source located within the State of Tennessee and for which requirements are set forth under the Federal CAIR NO_X Annual and Ozone Season Trading Programs in part 97 of this chapter must comply with such applicable requirements.

§ 52.2241 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

The owner or operator of each SO_2 source located within the State of Tennessee and for which requirements are set forth under the Federal CAIR SO_2 Trading Program in part 97 of this chapter must comply with such applicable requirements.

Subpart SS—Texas

■ 28. Subpart SS is amended by adding §§ 52.2283 and 52.2284 to read as follows:

§ 52.2283 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

The owner or operator of each NO_X source located within the State of Texas and for which requirements are set forth under the Federal CAIR NO_X Annual Trading Program in part 97 of this chapter must comply with such applicable requirements.

§ 52.2284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

The owner or operator of each SO_2 source located within the State of Texas and for which requirements are set forth under the Federal CAIR SO_2 Trading Program in part 97 of this chapter must comply with such applicable requirements.

Subpart VV—Virginia

■ 29. Subpart VV is amended by adding §§ 52.2440 and 52.2441 to read as follows:

§ 52.2440 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

The owner or operator of each NO_X source located within the State of Virginia and for which requirements are set forth under the Federal CAIR NO_X Annual and Ozone Season Trading Programs in part 97 of this chapter must comply with such applicable requirements.

§ 52.2441 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

The owner or operator of each SO_2 source located within the State of Virginia and for which requirements are set forth under the Federal CAIR SO_2 Trading Program in part 97 of this chapter must comply with such applicable requirements.

Subpart XX—West Virginia

■ 30. Subpart XX is amended by adding §§ 52.2540 and 52.2541 to read as follows:

§ 52.2540 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

The owner or operator of each NO_X source located within the State of West Virginia and for which requirements are set forth under the Federal CAIR NO_X Annual and Ozone Season Trading Programs in part 97 of this chapter must comply with such applicable requirements.

§ 52.2541 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

The owner or operator of each SO_2 source located within the State of West Virginia and for which requirements are set forth under the Federal CAIR SO_2 Trading Program in part 97 of this chapter must comply with such applicable requirements.

Subpart YY—Wisconsin

■ 31. Subpart YY is amended by adding §§ 52.2587 and 52.2588 to read as follows:

§ 52.2587 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

The owner or operator of each NO_X source located within the State of Wisconsin and for which requirements are set forth under the Federal CAIR NO_X Annual and Ozone Season Trading Programs in part 97 of this chapter must comply with such applicable requirements.

§ 52.2588 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

The owner or operator of each SO_2 source located within the State of Wisconsin and for which requirements are set forth under the Federal CAIR SO_2 Trading Program in part 97 of this chapter must comply with such applicable requirements.

PART 72—[AMENDED]

■ 1. The authority citation for Part 72 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

■ 2. Section 72.2 is amended, in the definition of "Receive or receipt", by revising the words "official correspondence log" to read "official log".

■ 3. Section 72.7 is amended as follows:

■ a. By revising paragraph (f)(2); and

■ b. In paragraph (f)(4)(i), by revising the words "become an affected unit under the Acid Rain Program and parts 70 and 71 of this chapter" to read, for purposes of applying parts 70 and 71 of this chapter, shall be treated as an affected unit under the Acid Rain Program". The revision reads as follows:

§ 72.7 New units exemption.

* * * * *

(f) * * *

(2) For any period for which a unit is exempt under this section:

(i) For purposes of applying parts 70 and 71 of this chapter, the unit shall not be treated as an affected unit under the Acid Rain Program and shall continue to be subject to any other applicable requirements under parts 70 and 71 of this chapter.

(ii) The unit shall not be eligible to be an opt-in source under part 74 of chapter.

* * * * *

■ 4. Section 72.8 is amended as follows:

■ a. By revising paragraph (d)(4); and

■ b. In paragraph (d)(6)(i) introductory text, by revising the words "become an affected unit under the Acid Rain Program and parts 70 and 71 of this chapter" to read ," for purposes of applying parts 70 and 71 of this chapter, shall be treated as an affected unit under the Acid Rain Program".

The revision reads as follows:

§ 72.8 Retired units exemption.

* * * * *

(d) * * *

(4) For any period for which a unit is exempt under this section:

(i) For purposes of applying parts 70 and 71 of this chapter, the unit shall not be treated as an affected unit under the Acid Rain Program and shall continue to be subject to any other applicable requirements under parts 70 and 71 of this chapter.

(ii) The unit shall not be eligible to be an opt-in source under part 74 of chapter.

* * * * *

§ 72.20 [Amended]

■ 5. Section 72.20 is amended, in paragraph (b), by revising the words "his or her actions" to read "his or her representations, actions".

§ 72.22 [Amended]

■ 6. Section 72.22 is amended, in paragraph (b), by revising the words "any action, representation, or failure to act" to read "any representation, action, inaction, or submission" whenever they appear.

§ 72.23 [Amended]

■ 7. Section 72.23 is amended as follows:

■ a. In paragraphs (a) and (b), by revising the words "submissions, actions, and inactions" to read "representations, actions, inactions, and submissions"; and

■ b. In paragraph (c)(1), by revising the words "a new owner" to read "an owner", by revising the words "such new owner" to read "such owner", by revising the words "submissions, actions, and inactions" to read "representations, actions, inactions, and submissions", and by revising the words "the new owner" to read "the owner."

§ 72.24 [Amended]

■ 8. Section 72.24 is amended as follows:

■ a. In paragraph (a)(1) by revising the words "is submitted." to read "is submitted, including identification and nameplate capacity of each generator served by each such unit";

■ b. In paragraph (a)(6), by revising the words "actions, inactions, or submissions" to read "representations, actions, inactions, or submissions"; and

■ c. In paragraph (a)(9)(ii), by revising the words "or ,if such multiple" to read ", except that, if such multiple".

§ 72.25 [Amended]

■ 9. Section 72.25 is amended, in paragraph (b), by revising the words "submission, action or inaction" to read "representation, action, inaction, or submission" and revise the words "submission, action, or inaction" to read "representation, action, inaction, or submission".

■ 10. Add a new 72.26 to read as follows:

§ 72.26 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission (in a format prescribed by the Administrator) to the Administrator provided for or required under this part and parts 73 through 77 of this chapter.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission (in a format prescribed by the Administrator) to the Administrator provided for or required under this part and parts 73 through 77 of this chapter.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative, as appropriate:

(i) "I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 72.26(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 72.26(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 72.26 is terminated."

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

PART 73—[AMENDED]

■ 1. The authority citation for part 73 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

§ 73.31 [Amended]

■ 2. Section 73.31 is amended, in paragraph (c)(1)(v), by revising the words "actions, inactions, or submissions" to read "representations, actions, inactions, or submissions".

■ 3. Section 73.33 is amended as follows:

■ a. In paragraph (d)(4), by revising the words "action, representation, or failure to act" to read "representation, action, inaction, or submission" and by revising the word "an action" to read "a representation, action, inaction, or submission";

■ b. In paragraph (e), by revising the word "actions" to read "representations, actions, inactions, or submissions";

■ c. In paragraph (f), by revising the words "any submission to" to read "any representation, action, inaction, or submission to" and revise the words "the recordation of transfers submitted by" to read "any representation, action, inaction, or submission of"; and

■ d. By adding a new paragraph (g) to read as follows:

§ 73.33 Authorized account representative.

* * * * *

(g) *Delegation by authorized account representative and alternate authorized account representative.* (1) An authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission (in a format prescribed by the Administrator) to the Administrator provided for or required under this part.

(2) An alternate authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission (in a format prescribed by the Administrator) to the Administrator provided for or required under this part.

(3) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (g)(1) or (2) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(i) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(ii) The name, address, e-mail address, telephone number, and, facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(iii) For each such natural person, a list of the type or types of electronic submissions under paragraph (g)(1) or (2) of this section for which authority is delegated to him or her;

(iv) The following certification statements by such authorized account representative or alternate authorized account representative:

(A) "I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 73.33(g)(4) shall be deemed to be an electronic submission by me."

(B) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 73.33(g)(4), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 73.33(g) is eliminated."

(4) A notice of delegation submitted under paragraph (g)(3) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(5) Any electronic submission covered by the certification in paragraph (g)(3)(iv)(A) of this section and made in accordance with a notice of delegation effective under paragraph (g)(4) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

PART 74—[AMENDED]

■ 1. The authority citation for Part 74 continues to read as follows:

Authority: 7601 and 7651 *et seq.*

§ 74.4 [Amended]

■ 2. In § 74.4, paragraph (c) is removed.

PART 78—[AMENDED]

■ 1. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, *et seq.*

■ 2. Section 78.1 is amended as follows:

■ a. In paragraph (b)(8)(ii), by revising "§ 97.256" to read "§ 96.256".

■ b. By adding new paragraphs (b)(10), (b)(11), and (b)(12) to read as follows:

§ 78.1 Purpose and scope.

* * * * *

(b) * * *

(10) Under subparts AA through II of part 97 of this chapter,

(i) The decision on the allocation of CAIR NO_X allowances under subpart EE of part 97 of this chapter.

(ii) The decision on the deduction of CAIR NO_X allowances, and the adjustment of the information in a submission and the decision on the deduction or transfer of CAIR NO_X allowances based on the information as adjusted, under § 97.154 of this chapter;

(iii) The correction of an error in a CAIR NO_X Allowance Tracking System account under § 97.156 of this chapter;

(iv) The decision on the transfer of CAIR NO_X allowances under § 97.161 of this chapter;

(v) The finalization of control period emissions data, including retroactive adjustment based on audit;

(vi) The approval or disapproval of a petition under § 97.175 of this chapter.

(11) Under subparts AAA through III of part 97 of this chapter,

(i) The decision on the deduction of CAIR SO_2 allowances, and the adjustment of the information in a submission and the decision on the deduction or transfer of CAIR SO_2 allowances based on the information as adjusted, under § 97.254 of this chapter;

(ii) The correction of an error in a CAIR SO_2 Allowance Tracking System account under § 97.256 of this chapter;

(iii) The decision on the transfer of CAIR SO_2 allowances under § 97.261 of this chapter;

(iv) The finalization of control period emissions data, including retroactive adjustment based on audit;

(v) The approval or disapproval of a petition under § 97.275 of this chapter.

(12) Under subparts AAAA through IIII of part 97 of this chapter,

(i) The decision on the allocation of CAIR NO_X Ozone Season allowances under subpart EEEE of part 97 of this chapter.

(ii) The decision on the deduction of CAIR NO_X Ozone Season allowances, and the adjustment of the information in a submission and the decision on the deduction or transfer of CAIR NO_X Ozone Season allowances based on the information as adjusted, under § 97.354 of this chapter;

(iii) The correction of an error in a CAIR NO_X Ozone Season Allowance Tracking System account under § 97.356 of this chapter;

(iv) The decision on the transfer of CAIR NO_X Ozone Season allowances under § 97.361;

(v) The finalization of control period emissions data, including retroactive adjustment based on audit;

(vi) The approval or disapproval of a petition under § 97.375 of this chapter.

* * * * *

■ 3. Section 78.3 is amended as follows:

■ a. In paragraph (b)(3)(i), by revising the words "under paragraph (a)(4), (5), or (6) of this section" to read "under paragraph (a)(4), (5), (6), (7), (8), or (9) of this section";

■ b. In paragraph (d)(3), by revising the words "account certificate of

Federal Register

Friday,
September 7, 2007

Part II

Environmental Protection Agency

40 CFR Parts 60, 72 and 75

Two Optional Methods for Relative Accuracy Test Audits of Mercury Monitoring Systems Installed on Combustion Flue Gas Streams and Several Amendments to Related Mercury Monitoring Provisions; Final Rule

Appendix B [Amended]

■ 3. Amend Performance Specification 12A in Appendix B to part 60 by revising sections 8.6.2, 8.6.4, 8.6.5, and 8.6.6.1 to read as follows:

Performance Specification 12A—Specifications and Test Procedures for Total Vapor Phase Mercury Continuous Emission Monitoring Systems in Stationary Sources

* * * * *

8.6.2 RM. Unless otherwise specified in an applicable subpart of the regulations, use Method 29, Method 30A, or Method 30B in appendix A to this part or American Society of Testing and Materials (ASTM) Method D6784–02 (incorporated by reference, see § 60.17) as the RM for Hg concentration. Do not include the filterable portion of the sample when making comparisons to the CEMS results. When Method 29, Method 30B, or ASTM D6784–02 is used, conduct the RM test runs with paired or duplicate sampling systems. When Method 30A is used, paired sampling systems are not required. If the RM and CEMS measure on a different moisture basis, data derived with Method 4 in appendix A to this part shall also be obtained during the RA test.

* * * * *

8.6.4 Number and Length of RM and Tests. Conduct a minimum of nine RM test runs. When Method 29, Method 30B, or ASTM D6784–02 is used, only test runs for which the paired RM trains meet the relative deviation criteria (RD) of this PS shall be used in the RA calculations. In addition, for Method 29 and ASTM D6784–02, use a minimum sample time of 2 hours and for Method 30A use a minimum sample time of 30 minutes.

Note: More than nine sets of RM tests may be performed. If this option is chosen, paired RM test results may be excluded so long as the total number of paired RM test results used to determine the CEMS RA is greater than or equal to nine. However, all data must be reported including the excluded data.

8.6.5 Correlation of RM and CEMS Data. Correlate the CEMS and the RM test data as to the time and duration by first determining from the CEMS final output (the one used for reporting) the integrated average pollutant concentration for each RM test period. Consider system response time, if important, and confirm that the results are on a consistent moisture basis with the RM test. Then, compare each integrated CEMS value against the corresponding RM value. When Method 29, Method 30A, Method 30B, or ASTM D6784–02 is used, compare each CEMS value against the corresponding average of the paired RM values.

8.6.6 * * *

8.6.6.1 When Method 29, Method 30B, or ASTM D6784–02 is used, outliers are identified through the determination of relative deviation (RD) of the paired RM tests. Data that do not meet the criteria should be flagged as a data quality problem. The primary reason for performing paired RM sampling is to ensure the quality of the RM data. The percent RD of paired data is the parameter used to quantify data quality. Determine RD for two paired data points as follows:

$$RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100 \qquad \text{Eq. 12A-1}$$

where C_a and C_b are concentration values determined from each of the two samples, respectively.

* * * * *

PART 72—PERMITS REGULATION

■ 4. The authority citation for part 72 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

■ 5. Revise the definition of "sorbent trap monitoring system" in § 72.2 as follows:

§ 72.2 Definitions.

* * * * *

Sorbent trap monitoring system means the equipment required by part 75 of this chapter for the continuous monitoring of Hg emissions, using paired sorbent traps containing iodated charcoal (IC) or other suitable reagents. This excepted monitoring system consists of a probe, the paired sorbent traps, an umbilical line, moisture removal components, an air tight sample pump, a gas flow meter, and an automated data acquisition and handling system. The monitoring system samples the stack gas at a rate proportional to the stack gas volumetric flowrate. The sampling is a batch process. Using the sample volume measured by the gas flow meter and the results of the analyses of the sorbent traps, the average mercury concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter (µg/dscm). Mercury mass emissions for each hour in the sampling period are calculated using the average Hg concentration for that period, in conjunction with contemporaneous hourly measurements of the stack gas flow rate, corrected for the stack moisture content.

* * * * *

PART 75—CONTINUOUS EMISSION MONITORING

■ 6. The authority citation for part 75 continues to read as follows:

Authority: 42 U.S.C. 7601, 7651k, and 7651k note.

■ 7. Amend § 75.15 as follows:

■ a. Revise paragraph (f);

■ b. Revise paragraph (i); and

■ c. Add new paragraph (k).

The revisions and additions read as follows:

§ 75.15 Special provisions for measuring Hg mass emissions using the excepted sorbent trap monitoring methodology.

* * * * *

(f) At the beginning and end of each sample collection period, and at least once in each unit operating hour during the collection period, the gas flow meter reading shall be recorded.

* * * * *

(i) All unit operating hours for which valid Hg concentration data are obtained with the primary sorbent trap monitoring system (as verified using the quality assurance procedures in appendix K to this part) shall be reported in the electronic quarterly report under § 75.84(f). For hours in which data from the primary monitoring system are invalid, the owner or operator may, in accordance with § 75.20(d), report valid Hg concentration data from: A certified redundant backup CEMS or sorbent trap monitoring system; a certified non-redundant backup CEMS or sorbent trap monitoring system; or an applicable reference method under § 75.22. If no quality-assured Hg concentration are available for a particular hour, the owner or operator shall report the appropriate substitute data value in accordance with § 75.39.

* * * * *

(k) During each RATA of a sorbent trap monitoring system, the type of sorbent material used by the traps shall be the same as for daily operation of the monitoring system. A new pair of traps shall be used for each RATA run. However, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

* * * * *

■ 8. Amend § 75.20 by adding new paragraph (d)(2)(ix) to read as follows:

§ 75.20 Initial certification and recertification procedures.

* * * * *

(d) * * *

(2) * * *

(ix) For non-redundant backup Hg CEMS and sorbent trap monitoring systems, and for like-kind replacement Hg analyzers, the following provisions apply in addition to, or, in some cases, in lieu of, the general requirements in paragraphs (d)(2)(i) through (d)(2)(viii) of this section:

(A) When a certified sorbent trap monitoring system is brought into service as a regular non-redundant backup monitoring system, the system shall be operated according to the procedures in § 75.15 and appendix K of this part;

(B) When a regular non-redundant backup Hg CEMS or a like-kind replacement Hg analyzer is brought into service, a linearity check with elemental Hg standards, as described in paragraph (c)(1)(ii) of this section and section 6.2 of appendix A of this part, and a single-point system integrity check, as described in section 2.6 of appendix B of this part, shall be performed. Alternatively, a 3-level system integrity check, as described in paragraph (c)(1)(vi) of this section and paragraph (g) of section 6.2 in appendix A of this part, may be performed in lieu of these two tests.

(C) The weekly single-point system integrity checks described in section 2.6 of appendix B of this part are required as long as a non-redundant backup Hg CEMS or like-kind replacement Hg analyzer remains in service, unless the daily calibrations of the Hg analyzer are done using a NIST-traceable source of oxidized Hg.

* * * * *

■ 9. Amend § 75.57 by revising paragraph (j)(7) to read as follows:

§ 75.57 General recordkeeping provisions.

* * * * *

(j) * * *

(7) Record the gas flow meter reading (in dscm, rounded to the nearest hundredth) at the beginning and end of the collection period and at least once in each unit operating hour during the collection period.

* * * * *

■ 10. Amend § 75.81 by revising paragraph (a)(1) to read as follows:

§ 75.81 Monitoring of Hg mass emissions and heat input at the unit level.

* * * * *

(a) * * *

(1) A Hg concentration monitoring system (as defined in § 72.2 of this chapter) or a sorbent trap monitoring system (as defined in § 72.2 of this chapter), to measure the mass concentration of total vapor phase Hg in the flue gas, including the elemental and oxidized forms of Hg, in micrograms per standard cubic meter (μg/scm); and

* * * * *

■ 11. Amend § 75.84 by revising paragraph (f)(1)(ii)(J) to read as follows:

§ 75.84 Recordkeeping and Reporting.

* * * * *

(f) * * *

(1) * * *

(ii) * * *

(J) For units using sorbent trap monitoring systems, the hourly gas flow meter readings taken between the initial and final meter readings for the data collection period; and

* * * * *

Appendix A to Part 75—[Amended]

■ 12. Amend Appendix A to part 75 by removing the twentieth sentence in paragraph (a) of section 6.5.7 which currently reads "For the RATA of a sorbent trap monitoring system, use the same size trap that is used for daily operation of the monitoring system." and adding in its place "For the RATA of a sorbent trap monitoring system, the type of sorbent material used by the traps shall be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.".

■ 13. Amend Appendix B to part 75 by revising section 1.5.2 to read as follows:

Appendix B to Part 75—Quality Assurance and Quality Control Procedures

* * * * *

1.5.2 Monitoring System Integrity and Data Quality

Explain the procedures used to perform the leak checks when sorbent traps are placed in service and removed from service. Also explain the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in section 8 of appendix K to this part. All reference meters used to calibrate the gas flow meters (e.g., wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST–traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST–traceability of the calibrator.

* * * * *

■ 14. Amend Appendix K to part 75 as follows:

■ a. Amend section 5.1 by revising Figure K–1;

■ b. Revise section 5.1.3;

■ c. Revise section 5.1.5;

■ d. Revise section 7.1.3;

■ e. Revise section 7.2.3;

■ f. Revise section 7.2.5;

■ g. Amend section 8.0 by revising Table K–1;

■ h. Revise section 9.2;

■ i. Revise section 10.4;

■ j. Remove and reserve section 11.5;

■ k. Revise section 11.6; and

■ l. Revise section 11.7.

The revisions and additions read as follows:

Appendix K to Part 75—Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems

* * * * *

5.1 * * *

BILLING CODE 6560–50–C

Consultation and Coordination with Indian Tribal Governments

This rule does not have tribal implications as defined by Executive Order 13175, Consultation and Coordination with Indian Tribal Governments. Therefore, advance consultation with Tribes is not required.

Controlling Paperwork Burdens on the Public

This rule does not require any record keeping or reporting requirements or other information collection requirements as defined in 5 CFR part 1320 not already approved for use and, therefore, imposes no additional paperwork burden on the public. Accordingly, the review provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501, *et seq.*) and implementing regulations at 5 CFR part 1320 do not apply.

List of Subjects in 36 CFR Part 223

Administrative practice and procedures, Forests and forest products, Exports, Government contracts, National forests, Reporting and record keeping requirements.

■ For the reasons set forth in the preamble, the Forest Service is amending part 223 of title 36 of the Code of Federal Regulations as follows:

PART 223—SALE AND DISPOSAL OF NATIONAL FOREST SYSTEM TIMBER

■ 1. The authority citation for part 223 continues to read as follows:

Authority: 90 Stat. 2958, 16 U.S.C. 472a; 98 Stat. 2213, 16 U.S.C. 618, 104 Stat. 714–726, 16 U.S.C. 620–620j, unless otherwise noted.

Subpart B—Timber Sale Contracts

■ 2. Revise § 223.85(c) to read as follows:

§ 223.85 Noncompetitive sale of timber.

* * * * *

(c) Extraordinary conditions, as provided for in 16 U.S.C. 472a(d), includes those conditions under which contracts for the sale or exchange of timber or other forest products must be suspended, modified, or terminated under the terms of such contracts to prevent environmental degradation or resource damage, or as the result of administrative appeals, litigation, or court orders. Notwithstanding the provisions of paragraph (a) of this section or any other regulation in this part, when such extraordinary conditions exist on sales not addressed in paragraph (b) of this section, the Secretary of Agriculture may allow forest officers to, without advertisement, modify those contracts by substituting timber or other forest products from outside the contract area specified in the contract for timber or forest products within the area specified in the contract. When such extraordinary conditions exist, the Forest Service and the purchaser shall make good faith efforts to identify replacement timber or forest products of similar volume, quality, value, access, and topography. When replacement timber or forest products agreeable to both parties is identified, the contract will be modified to reflect the changes associated with the substitution, including a rate redetermination. Concurrently, both parties will sign an agreement waiving any future claims for damages associated with the deleted timber or forest products, except those specifically provided for under the contract up to the time of the modification. If the Forest Service and the purchaser cannot reach agreement on satisfactory replacement timber or forest products, or the proper value of such material, either party may opt to end the search. Replacement timber or forest products must come from the same National Forest as the original contract. The term National Forest in this paragraph refers to an administrative unit headed by a single Forest Supervisor. Only timber or forest products for which a decision authorizing its harvest has been made and for which any applicable appeals or objection process has been completed may be considered for replacement pursuant to this paragraph. The value of replacement timber or forest products may not exceed the value of the material it is replacing by more than $10,000, as determined by standard Forest Service appraisal methods.

Dated: October 12, 2007.

Mark Rey,

Under Secretary, Natural Resources and Environment.

[FR Doc. E7–20625 Filed 10–18–07; 8:45 am]

BILLING CODE 3410–11–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 60, 72, 78, 96, and 97

[EPA–HQ–OAR–2007–0012; FRL–8483–7]

RIN 2060–AO33

Revisions to Definition of Cogeneration Unit in Clean Air Interstate Rule (CAIR), CAIR Federal Implementation Plans, Clean Air Mercury Rule (CAMR); and Technical Corrections to CAIR, CAIR FIPs, CAMR, and Acid Rain Program Rules

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Clean Air Interstate Rule (CAIR), CAIR Federal Implementation Plans (FIPs), and Clean Air Mercury Rule (CAMR) each include an exemption for cogeneration units that meet certain criteria. In light of information concerning biomass-fired cogeneration units that may not qualify for the exemption due to their particular combination of fuel and technical design characteristics, EPA is changing the cogeneration unit definition in CAIR, the CAIR model cap-and-trade rules, the CAIR FIPs, CAMR, and the CAMR model cap-and-trade rule. Specifically, EPA is revising the calculation methodology for the efficiency standard in the cogeneration unit definition to exclude energy input from biomass making it more likely that units co-firing biomass will be able to meet the efficiency standard and qualify for exemption. Because this change will only affect a small number of relatively low emitting units, it will have little effect on the projected emissions reductions and the environmental benefits of these rules. If EPA finalizes the proposed CAMR Federal Plan, it intends to make the definitions in that rule conform to the CAMR model cap-and-trade rule and thus, with today's action. This action also clarifies the term "total energy input" used in the efficiency calculation and makes minor technical corrections to CAIR, the CAIR FIPs, CAMR, and the Acid Rain Program rules.

DATES: The final rule is effective on November 19, 2007.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2007–0012. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, i.e., Confidential Business Information (CBI) or other information whose

§ 60.24 Emission standards and compliance schedules.

* * * * *

(h) * * *

(6)(i) * * * Before January 1, 2009, a State's regulations shall be considered to be substantively identical to subpart HHHH of this part, or differing substantively only as set forth in paragraph (h)(6)(ii) of this section, regardless of whether the State's regulations include the definition of "Biomass", paragraph (3) of the definition of "Cogeneration unit", and the second sentence of the definition of "Total energy input" in § 60.4102 of this chapter promulgated on October 19, 2007, provided that the State timely submits to the Administrator a State plan that revises the State's regulations to include such provisions. Submission to the Administrator of a State plan that revises the State's regulations to include such provisions shall be considered timely if the submission is made by January 1, 2010.

* * * * *

(8) * * * * *

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other nonmerchantable material, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

* * * * *

Cogeneration unit means * * *

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

* * * * *

Total energy input means * * * Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55(W + 9H)$$

Where:

LHV = lower heating value of fuel in Btu/lb,
HHV = higher heating value of fuel in Btu/lb,
W = Weight % of moisture in fuel, and
H = Weight % of hydrogen in fuel.

* * * * *

■ 6. Section 60.4102 is amended as follows:

■ a. By adding in alphabetical order a new definition of "Biomass";

■ b. In the definition of "Cogeneration unit", by removing the period at the end of paragraph (2)(ii) and adding in its place a semicolon and by adding a new paragraph (3); and

■ c. By adding a sentence at the end of the definition of "Total energy input" to read as follows:

§ 60.4102 Definitions.

* * * * *

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other nonmerchantable material, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

* * * * *

Cogeneration unit means * * *

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

* * * * *

Total energy input means * * * Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55(W + 9H)$$

Where:

LHV = lower heating value of fuel in Btu/lb,
HHV = higher heating value of fuel in Btu/lb,
W = Weight % of moisture in fuel, and
H = Weight % of hydrogen in fuel.

* * * * *

PART 72—PERMITS REGULATION

■ 7. The authority citation for Part 72 is revised to read as follows:

Authority: 42 U.S.C. 7601 and 7651 *et seq.*

§ 72.24 [Amended]

■ 8. Section 72.24 is amended, in paragraph (a)(9) introductory text, by removing the words "life-of-the-unit, firm power contractual arrangements" and adding in their place the words "a life-of-the-unit, firm power contractual arrangement".

PART 78—APPEAL PROCEDURES

■ 9. The authority citation for Part 78 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7411, 7426, 7601, and 7651, *et seq.*

■ 10. Section 78.1 is amended by revising paragraph (a)(1) to read as follows:

§ 78.1 Purpose and scope.

(a)(1) This part shall govern appeals of any final decision of the Administrator under subpart HHHH of part 60 of this chapter or State regulations approved under § 60.24(h)(6)(i) or (ii) of this chapter, part 72, 73, 74, 75, 76, or 77 of this chapter, subparts AA through II of part 96 of this chapter or State regulations approved under § 51.123(o)(1) or (2) of this chapter, subparts AAA through III of part 96 of this chapter or State regulations approved under § 51.124(o)(1) or (2) of this chapter, subparts AAAA through IIII of part 96 of this chapter or State regulations approved under § 51.123(aa)(1) or (2) of this chapter, or part 97 of this chapter; provided that matters listed in § 78.3(d) and preliminary, procedural, or intermediate decisions, such as draft Acid Rain permits, may not be appealed. All references in paragraph (b) of this section and in § 78.3 to subpart HHHH of part 60 of this chapter, subparts AA through II of part 96 of this chapter, subparts AAA through III of part 96 of this chapter, and subparts AAAA through IIII of part 96 of this chapter shall be read to include the comparable provisions in State regulations approved under § 60.24(h)(6)(i) or (ii) of this chapter, § 51.123(o)(1) or (2) of this chapter, § 51.124(o)(1) or (2) of this chapter, and § 51.123(aa)(1) or (2) of this chapter, respectively.

* * * * *

PART 96—[AMENDED]

■ 11. The authority citation for Part 96 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7601, and 7651, *et seq.*

■ 12. Section 96.102 is amended as follows:

■ a. By adding in alphabetical order a new definition of "Biomass";

Federal Register

Thursday,
January 24, 2008

Part II

Environmental Protection Agency

40 CFR Parts 72 and 75

Revisions to the Continuous Emissions Monitoring Rule for the Acid Rain Program, NO_X Budget Trading Program, Clean Air Interstate Rule, and the Clean Air Mercury Rule; Final Rule

Dated: December 19, 2007.

Stephen L. Johnson,

Administrator.

■ For the reasons set forth in the preamble, parts 72 and 75 of chapter I of title 40 of the Code of Federal Regulations are amended as follows:

PART 72—PERMITS REGULATION

■ 1. The authority citation for part 72 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

Subpart A—Acid Rain Program General Provisions

■ 2. Section 72.2 is amended as follows:
■ a. Revising the definition of "Capacity factor";
■ b. In the definition of "Diluent cap", by removing the words ", CO_2 mass emission rate, or heat input rate," after the words "NO_X emission rate";
■ c. In the definition of "EPA protocol gas", by adding a new sentence to the end of the definition;
■ d. Revising the definition of "Excepted monitoring system";
■ e. Adding the new definitions in alphabetical order for "Air Emission Testing Body (AETB)", "EPA Protocol Gas Verification Program", "Long-term cold storage", "NIST traceable elemental Hg standards", "NIST traceable source of oxidized Hg", "Qualified Individual", and "Specialty gas producer"; and
■ f. Removing the definition for "Research gas material (RGM)"

The revisions and additions read as follows:

§ 72.2 Definitions.

* * * * *

Air Emission Testing Body (AETB) means a company or other entity that conducts Air Emissions Testing as described in ASTM D7036–04 (incorporated by reference under § 75.6 of this part).

* * * * *

Capacity factor means either:

(1) The ratio of a unit's actual annual electric output (expressed in MWe/hr) to the unit's nameplate capacity (or maximum observed hourly gross load (in MWe/hr) if greater than the nameplate capacity) times 8760 hours; or

(2) The ratio of a unit's annual heat input (in million British thermal units or equivalent units of measure) to the unit's maximum rated hourly heat input rate (in million British thermal units per hour or equivalent units of measure) times 8,760 hours.

* * * * *

EPA protocol gas * * * On and after January 1, 2009, vendors advertising certification with the EPA Traceability Protocol *or* distributing gases as "EPA Protocol Gas" must participate in the EPA Protocol Gas Verification Program. Non-participating vendors may not use "EPA" in any form of advertising for these products, unless approved by the Administrator.

EPA Protocol Gas Verification Program means the EPA Protocol Gas audit program described in Section 2.1.10 of the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA–600/R–97/121 (EPA Protocol Procedure) or such revised procedure as approved by the Administrator.

* * * * *

Excepted monitoring system means a monitoring system that follows the procedures and requirements of § 75.15 of this chapter, § 75.19 of this chapter, § 75.81(b) of this chapter or of appendix D, or E to part 75 for approved exceptions to the use of continuous emission monitoring systems.

* * * * *

Long-term cold storage means the complete shutdown of a unit intended to last for an extended period of time (at least two calendar years) where notice for long-term cold storage is provided under § 75.61(a)(7).

* * * * *

NIST traceable elemental Hg standards means either:

(1) Compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards"; or

(2) Calibration gases having known concentrations of elemental Hg, produced by a generator that fully meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators".

* * * * *

NIST traceable source of oxidized Hg means a generator that: Is capable of providing known concentrations of vapor phase mercuric chloride ($HgCl_2$), and that fully meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Oxidized Mercury Gas Generators".

* * * * *

Qualified Individual means an individual who meets the requirements as described in ASTM D7036–04, "Standard Practice for Competence of Air Emission Testing Bodies" (incorporated by reference under § 75.6 of this part).

* * * * *

Specialty gas producer means an organization that prepares and analyzes compressed gas mixtures for use as calibration gases and that offers the mixtures for sale to end users or to third-party vendors for resale to end users.

* * * * *

PART 75—CONTINUOUS EMISSION MONITORING

■ 3. The authority citation for Part 75 continues to read as follows:

Authority: 42 U.S.C. 7601, and 7651k, and 7651k note.

Subpart A—General

■ 4. Section 75.4 is amended by revising paragraph (d) to read as follows:

§ 75.4 Compliance dates.

* * * * *

(d) This paragraph, applies to affected units under the Acid Rain Program and to units subject to a State or Federal pollutant mass emissions reduction program that adopts the emission monitoring and reporting provisions of this part. In accordance with § 75.20, for an affected unit which, on the applicable compliance date, is either in long-term cold storage (as defined in § 72.2 of this chapter) or is shut down as the result of a planned outage or a forced outage, thereby preventing the required continuous monitoring system certification tests from being completed by the compliance date, the owner or operator shall provide notice of such unit storage or outage in accordance with § 75.61(a)(3) or § 75.61(a)(7), as applicable. For the planned and unplanned unit outages described in this paragraph, the owner or operator shall ensure that all of the continuous monitoring systems for SO_2, NO_X, CO_2, Hg, opacity, and volumetric flow rate required under this part (or under the applicable State or Federal mass emissions reduction program) are installed and that all required certification tests are completed no later than 90 unit operating days or 180 calendar days (whichever occurs first) after the date that the unit recommences commercial operation, notice of which date shall be provided under § 75.61(a)(3) or § 75.61(a)(7), as applicable. The owner or operator shall determine and report SO_2 concentration, NO_X emission rate, CO_2 concentration, Hg concentration, and flow rate data (as applicable) for all unit operating hours after the applicable compliance date until all of the required certification tests are successfully completed, using either:

(1) The maximum potential concentration of SO_2 (as defined in section 2.1.1.1 of appendix A to this part), the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter, the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, the maximum potential Hg concentration, as defined in section 2.1.7.1 of appendix A to this part, or the maximum potential CO_2 concentration, as defined in section 2.1.3.1 of appendix A to this part; or

(2) The conditional data validation provisions of § 75.20(b)(3); or

(3) Reference methods under § 75.22(b); or

(4) Another procedure approved by the Administrator pursuant to a petition under § 75.66.

* * * * *

■ 5. Section 75.6 is amended by:

■ a. Removing "D129–91" and adding in its place "D129–00", in paragraph (a)(1);

■ b. Removing "D240–87 (Reapproved 1991)" and adding in its place "D240–00", in paragraph (a)(2);

■ c. Removing "D287–82 (Reapproved 1987)" and adding in its place "D287–92 (Reapproved 2000)", in paragraph (a)(3);

■ d. Removing "D388–92" and adding in its place "D388–99", in paragraph (a)(4);

■ e. Removing and reserving paragraph (a)(5);

■ f. Removing "D1072–90" and adding in its place "D1072–06", and also by adding the phrase "by Combustion and Barium Chloride Titration" after the word "Gases", in paragraph (a)(6);

■ g. Removing "D1217–91" and adding in its place "D1217–93 (Reapproved 1998)", in paragraph (a)(7);

■ h. Removing the phrase "(Reapproved 1990)", and by removing "D1250–80" and adding in its place "D1250–07", and also by adding the phrase "Use of the" after the first occurrence of the word "for", in paragraph (a)(8);

■ i. Removing the phrase "D1298–85 (Reapproved 1990), Standard Practice for Density, Relative Density (Specific Gravity)" and adding in its place "D1298–99, Standard Test Method for Density, Relative Density (Specific Gravity),", in paragraph (a)(9);

■ j. Removing "D1480–91" and adding in its place "D1480–93 (Reapproved 1997)", in paragraph (a)(10);

■ k. Removing "D1481–91" and adding in its place "D1481–93 (Reapproved 1997)", in paragraph (a)(11);

■ l. Removing "D1552–90" and adding in its place "D1552–01", and also by removing the phrase, "High Temperature" and adding in its place "High-Temperature", in paragraph (a)(12);

■ m. Removing "D1826–88" and adding in its place "D1826–94 (Reapproved 1998)", in paragraph (a)(13);

■ n. Removing "D1945–91" and adding in its place "D1945–96 (Reapproved 2001)", in paragraph (a)(14);

■ o. Adding the phrase "(Reapproved 2006)" after "D1946–90", in paragraph (a)(15);

■ p. Removing and reserving paragraph (a)(16);

■ q. Removing "D2013–86" and adding in its place "D2013–01", and also by removing the phrase, "Method of", and adding in its place, "Practice for", in paragraph (a)(17);

■ r. Removing and reserving paragraph (a)(18);

■ s. Removing "D2234–89" and adding in its place "D2234–00", and also by removing the phrase "Test Methods", and adding in its place, "Practice", in paragraph (a)(19);

■ t. Removing and reserving paragraph (a)(20);

■ u. Removing "D2502–87" and adding in its place "D2502–92 (Reapproved 1996)", in paragraph (a)(21);

■ v. Removing "D2503–82 (Reapproved 1987)" and adding in its place "D2503–92 (Reapproved 1997)", and also by removing the phrase "Molecular Weight (Relative Molecular Mass)", and by adding in its place, "Relative Molecular Mass (Molecular Weight)", in paragraph (a)(22);

■ w. Removing "D2622–92" and adding in its place "D2622–98", and also by removing the phrase "X-Ray Spectrometry", and adding in its place "Wavelength Dispersive X-ray Fluorescence Spectrometry", in paragraph (a)(23);

■ x. Removing "D3174–89" and adding in its place "D3174–00", and also by removing the word "From" and adding in its place "from", in paragraph (a)(24);

■ y. Adding the phrase "(Reapproved 2002)" after "D3176–89", in paragraph (a)(25);

■ z. Removing "D3177–89" and adding in its place the phrase " D3177–02 (Reapproved 2007)" in paragraph (a)(26);

■ aa. Removing " D3178–89 (1997), "Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke" and adding in its place "D5373–02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke" in paragraph (a)(27);

■ bb. Removing "D3238–90" and adding in its place "D3238–95 (Reapproved 2000)", in paragraph (a)(28);

■ cc. Removing "D3246–81 (Reapproved 1987)" and adding in its place "D3246–96", and also by removing the word "By" and adding in its place, "by", in paragraph (a)(29);

■ dd. Removing and reserving paragraph (a)(30);

■ ee. Removing "D3588–91" and adding in its place "D3588–98", and also by removing the phrase, "(Specific Gravity)", in paragraph (a)(31);

■ ff. Removing "D4052–91" and adding in its place "D4052–96 (Reapproved 2002)", in paragraph (a)(32);

■ gg. Removing "D4057–88" and adding in its place "D4057–95 (Reapproved 2000)", in paragraph (a)(33);

■ hh. Removing "D4177–82 (Reapproved 1990)" and adding in its place "D4177–95 (Reapproved 2000)", in paragraph (a)(34);

■ ii. Removing "D4239–85" and adding in its place "D4239–02", and also by removing the phrase "High Temperature", and adding in its place "High-Temperature", in paragraph (a)(35);

■ jj. Removing "D4294–90" and adding in its place "D4294–98", adding the words "and Petroleum" after the word "Petroleum", by removing the word "X-Ray" and adding in its place, "X-ray", and by removing the word "Spectroscopy" and adding in its place, "Spectrometry" in paragraph (a)(36);

■ kk. Removing the phrase "(Reapproved 1989)" and adding in its place the phrase "(Reapproved 2006)", in paragraph (a)(37);

■ ll. Removing "(reapproved 2004)", and adding in its place, "(Reapproved 2004)", in paragraph (a)(38);

■ mm. Adding the phrase "(Reapproved 2006)" after "D4891–89", in paragraph (a)(39);

■ nn. Removing "D5291–92" and adding in its place "D5291–02", in paragraph (a)(40);

■ oo. Removing "D5373–93", and adding in its place "D5373–02 (Reapproved 2007)" and adding the word "Test" after the word "Standard", in paragraph (a)(41);

■ pp. Removing "D5504–94" and adding in its place "D5504–01", in paragraph (a)(42);

■ qq. Adding new paragraphs (a)(45), (a)(46), (a)(47), (a)(48), and (a)(49);

■ rr. Removing the phrase "ASME MFC–3M–1989 with September 1990 Errata" and adding in its place the phrase "ASME MFC–3M–2004 (Revision of ASME MFC–3M–1989 (R1995))", in paragraph (b)(1);

■ ss. Removing the date "1990" and adding in its place the date "1997" in the parenthetical, in paragraph (b)(2);

■ tt. Adding the phrase "(Reaffirmed 1994)" after "ASME–MFC–5M–1985,", in paragraph (b)(3);

■ uu. Removing the phrase "1987 with June 1987 Errata" and adding in its place the number "1998" at the end of "MFC–6M–", and also by removing "Flow Meters" and adding in its place, "Flowmeters", in paragraph (b)(4);

■ vv. Removing the phrase "with December 1989 Errata" and adding in its place the phrase "(Reaffirmed 2001)", in paragraph (b)(6);

■ ww. Removing the number "86" and adding in its place the number "96" at the end of "GPA Standard 2172–", in paragraph (d)(1);

■ xx. Removing the number "90" and adding in its place the number "00" at the end of "GPA Standard 2261–00", in paragraph (d)(2);

■ yy. Revising paragraphs (f)(1) and (f)(3); and

■ zz. Adding new paragraph (f)(4).

The revisions and additions read as follows:

§ 75.6 Incorporation by reference.

* * * * *

(a) * * *

(45) ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, for appendix D of this part.

(46) ASTM D4809–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), for appendices D and F of this part.

(47) ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke, for appendices A, D, and F of this part.

(48) ASTM D7036–04, Standard Practice for Competence of Air Emission Testing Bodies, for appendices A, B, and E of this part.

(49) ASTM D5453–06, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence, for appendix D of this part.

* * * * *

(f) * * *

(1) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3—Tank Gauging, Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005; Section 1B—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001; Section 2—Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, First Edition, August 1995 (Reaffirmed March 2006); Section 3—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996; Section 4—Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, First Edition April 1995 (Reaffirmed, March 2006); and Section 5—Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, First Edition March 1997 (Reaffirmed, March 2003); for § 75.19.

* * * * *

(3) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4—Proving Systems, Section 2—Pipe Provers (Provers Accumulating at Least 10,000 Pulses), Second Edition, March 2001, and Section 5—Master-Meter Provers, Second Edition, May 2000, for appendix D to this part.

(4) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices (First Edition, August 2005), for appendix D to this part.

■ 6. Section 75.11 is amended by:

■ a. Revising the heading of the section;

■ b. Adding the phrase "and 14.0% for natural gas (boilers, only);" after the word "wood;", in paragraph (b)(1);

■ c. Revising paragraph (d)(3);

■ d. Revising paragraphs (e) introductory text and (e)(1);

■ e. Removing and reserving paragraph (e)(2);

■ f. Revising paragraph (e)(3) introductory text;

■ g. Add new paragraph (e)(4); and

■ h. Revising paragraph (f).

The revisions and additions read as follows:

§ 75.11 Specific provisions for monitoring SO_2 emissions.

* * * * *

(d) * * *

(3) By using the low mass emissions excepted methodology in § 75.19(c) for estimating hourly SO_2 mass emissions if the affected unit qualifies as a low mass emissions unit under § 75.19(a) and (b). If this option is selected for SO_2, the LME methodology must also be used for NO_X and CO_2 when these parameters are required to be monitored by applicable program(s).

(e) *Special considerations during the combustion of gaseous fuels.* The owner or operator of an affected unit that uses a certified flow monitor and a certified diluent gas (O_2 or CO_2) monitor to measure the unit heat input rate shall, during any hours in which the unit combusts only gaseous fuel, determine SO_2 emissions in accordance with paragraph (e)(1) or (e)(3) of this section, as applicable.

(1) If the gaseous fuel qualifies for a default SO_2 emission rate under Section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part, the owner or operator may determine SO_2 emissions by using Equation F–23 in appendix F to this part. Substitute into Equation F–23 the hourly heat input, calculated using the certified flow monitoring system and the certified diluent monitor (according to the applicable equation in section 5.2 of appendix F to this part), in conjunction with the appropriate default SO_2 emission rate from section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part. When this option is chosen, the owner or operator shall perform the necessary data acquisition and handling system tests under § 75.20(c), and shall meet all quality control and quality assurance requirements in appendix B to this part for the flow monitor and the diluent monitor; or

(2) [Reserved]

(3) The owner or operator may determine SO_2 mass emissions by using a certified SO_2 continuous monitoring system, in conjunction with the certified flow rate monitoring system. However, if the gaseous fuel is very low sulfur fuel (as defined in § 72.2 of this chapter), the SO_2 monitoring system shall meet the following quality assurance provisions when the very low sulfur fuel is combusted:

* * * * *

(4) The provisions in paragraph (e)(1) of this section, may also be used for the combustion of a solid or liquid fuel that meets the definition of very low sulfur fuel in § 72.2 of this chapter, mixtures of such fuels, or combinations of such fuels with gaseous fuel, if the owner or operator submits a petition under § 75.66 for a default SO_2 emission rate for each fuel, mixture or combination, and if the Administrator approves the petition.

(f) *Other units.* The owner or operator of an affected unit that combusts wood, refuse, or other material in addition to oil or gas shall comply with the monitoring provisions for coal-fired units specified in paragraph (a) of this section, except where the owner or operator has an approved petition to use the provisions of paragraph (e)(1) of this section.

■ 7. Section 75.12 is amended by:

■ a. Revising the section heading;

■ b. Removing the word "and" before the number "15.0%", and by adding the phrase "; and 18.0% for natural gas (boilers, only)" after the word "wood", in paragraph (b); and

■ c. Revising paragraph (e)(3).

The revisions read as follows:

§ 75.12 Specific provisions for monitoring NO_X emission rate.

* * * * *

(e) * * *

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly NO_X emission rate and hourly NO_X mass emissions, if applicable under § 75.19(a) and (b). If this option is selected for NO_X, the LME methodology must also be used for SO_2 and CO_2 when these parameters are required to be monitored by applicable program(s).

* * * * *

■ 8. Section 75.13 is amended by revising paragraph (d)(3) to read as follows:

§ 75.13 Specific provisions for monitoring CO_2 emissions.

* * * * *

(d) * * *

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly CO_2 mass emissions, if applicable under § 75.19(a) and (b). If this option is selected for CO_2, the LME methodology must also be used for NO_X and SO_2 when these parameters are required to be monitored by applicable program(s).

■ 9. Section 75.14 is amended by adding paragraph (e) to read as follows:

§ 75.14 Specific provisions for monitoring opacity.

* * * * *

(e) Unit with a certified particulate matter (PM) monitoring system. If, for a particular affected unit, the owner or operator installs, certifies, operates, maintains, and quality-assures a continuous particulate matter (PM) monitoring system in accordance with Procedure 2 in appendix F to part 60 of this chapter, the unit shall be exempt from the opacity monitoring requirement of this part.

■ 10. Section 75.15 is amended by:

■ a. Removing the reference "(j)" and adding the reference "(l)" in its place in the introductory paragraph;

■ b. Revising paragraph (h); and

■ c. Adding paragraph (l).

The revisions and additions read as follows:

§ 75.15 Special provisions for measuring Hg mass emissions using the excepted sorbent trap monitoring methodology.

* * * * *

(h) The hourly Hg mass emissions for each collection period are determined using the results of the analyses in conjunction with contemporaneous hourly data recorded by a certified stack flow monitor, corrected for the stack gas moisture content. For each pair of sorbent traps analyzed, the average of the two Hg concentrations shall be used for reporting purposes under (75.84(f). Notwithstanding this requirement, if, due to circumstances beyond the control of the owner or operator, one of the paired traps is accidentally lost, damaged, or broken and cannot be analyzed, the results of the analysis of the other trap may be used for reporting purposes, provided that:

(1) The other trap has met all of the applicable quality-assurance requirements of this part; and

(2) The Hg concentration measured by the other trap is multiplied by a factor of 1.111.

* * * * *

(l) Whenever the type of sorbent material used by the traps is changed, the owner or operator shall conduct a diagnostic RATA of the modified sorbent trap monitoring system within 720 unit or stack operating hours after the date and hour when the new sorbent material is first used. If the diagnostic RATA is passed, data from the modified system may be reported as quality-assured, back to the date and hour when the new sorbent material was first used. If the RATA is failed, all data from the modified system shall be invalidated, back to the date and hour when the new sorbent material was first used, and data from the system shall remain invalid until a subsequent RATA is passed. If the required RATA is not completed within 720 unit or stack operating hours, but is passed on the first attempt, data from the modified system shall be invalidated beginning with the first operating hour after the 720 unit or stack operating hour window expires and data from the system shall remain invalid until the date and hour of completion of the successful RATA.

■ 11. Section 75.16 is amended by:

■ a. Revising paragraph (b)(1)(ii);

■ b. Adding the word "rate" after the phrase "report heat input" in the last sentence, in paragraph (e)(1); and

■ c. In the second sentence of paragraphs (e)(3) by removing both occurrences of the phrase "steam flow" and adding in its place the phrase "steam load" and adding the phrase "or mmBtu/hr thermal output" inside the parentheses, after the phrase "in 1000 lb/hr", in paragraph (e)(3).

The revisions read as follows:

§ 75.16 Special provisions for monitoring emissions from common, bypass, and multiple stacks for SO_2 emissions and heat input determinations.

* * * * *

(b) * * *

(1) * * *

(ii) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system and flow monitoring system in the common stack and combine emissions for the affected units for recordkeeping and compliance purposes.

* * * * *

■ 12. Section 75.17 is amended by revising paragraph (d)(2) to read as follows:

§ 75.17 Special provisions for monitoring emissions from common, bypass, and multiple stacks for NO_X emission rate.

* * * * *

(d) * * *

(2) Install, certify, operate, and maintain a NO_X-diluent CEMS only on the main stack. If this option is chosen, it is not necessary to designate the exhaust configuration as a multiple stack configuration in the monitoring plan required under § 75.53, with respect to NO_X or any other parameter that is monitored only at the main stack. For each unit operating hour in which the bypass stack is used and the emissions are either uncontrolled (or the add-on controls are not documented to be operating properly), report the maximum potential NO_X emission rate (as defined in § 72.2 of this chapter). The maximum potential NO_X emission rate may be specific to the type of fuel combusted in the unit during the bypass (see § 75.33(c)(8)). Alternatively, for a unit with NO_X add-on emission controls, for each unit operating hour in which the bypass stack is used and the add-on NO_X emission controls are not bypassed, the owner or operator may report the maximum controlled NO_X emission rate (MCR) instead of the maximum potential NO_X emission rate provided that the add-on controls are documented to be operating properly, as described in the quality assurance/quality control program for the unit, required by section 1 in appendix B of this part. To provide the necessary documentation, the owner or operator shall record parametric data to verify the proper operation of the NO_X add-on emission controls as described in § 75.34(d). Furthermore, the owner or operator shall calculate the MCR using the procedure described in section 2.1.2.1(b) of appendix A to this part where the words "maximum potential NO_X emission rate (MER)" shall apply instead of the words "maximum

controlled NO_X emission rate (MCR)" and by using the NO_X MEC in the calculations instead of the NO_X MPC.

■ 13. Section 75.19 is amended by:
■ a. Revising paragraph (a)(1);
■ b. Revising paragraph (c)(1)(i);
■ c. Revising paragraph (c)(1)(iv)(A)(3);
■ d. Removing the words "Method 20" from paragraph (c)(1)(iv)(A)(4);
■ e. Removing the words "Method 20" from the definition of NO_X obs in the nomenclature for Equation LM–1a under paragraph (c)(1)(iv)(A);
■ f. Adding the phrase, "that meets the quality assurance requirements of either: this part, or appendix F to part 60 of this chapter, or a comparable State CEM program," after the abbreviation "CEMS", in paragraph (c)(1)(iv)(G);
■ g. Adding paragraphs (c)(1)(iv)(I)(3), (4), (5) and (6);
■ h. Revising paragraph (c)(3)(ii)(B)(2);
■ i. Revising paragraph (c)(3)(ii)(H);
■ j. Removing the words "from Table LM–1 of this section" from the first sentence of paragraph (c)(4)(i)(A);
■ k. Revising the heading for paragraph (c)(4)(ii); and
■ l. Adding paragraph (c)(4)(ii)(D).

The revisions and additions read as follows:

§ 75.19 Optional SO_2, NO_X, and CO_2 emissions calculation for low mass emissions units.

* * * * *

(a) * * *

(1) For units that meet the requirements of this paragraph (a)(1) and paragraphs (a)(2) and (b) of this section, the low mass emissions (LME) excepted methodology in paragraph (c) of this section may be used in lieu of continuous emission monitoring systems or, if applicable, in lieu of methods under appendices D, E, and G to this part, for the purpose of determining unit heat input, NO_X, SO_2, and CO_2 mass emissions, and NO_X emission rate under this part. If the owner or operator of a qualifying unit elects to use the LME methodology, it must be used for all parameters that are required to be monitored by the applicable program(s). For example, for an Acid Rain Program LME unit, the methodology must be used to estimate SO_2, NO_X, and CO_2 mass emissions, NO_X emission rate, and unit heat input.

* * * * *

(c) * * *

(1) * * *

(i) If the unit combusts only natural gas and/or fuel oil, use Table LM–1 of this section to determine the appropriate SO_2 emission rate for use in calculating hourly SO_2 mass emissions under this section. Alternatively, for fuel oil combustion, a lower, fuel-specific SO_2 emission factor may be used in lieu of the applicable emission factor from Table LM–1, if a federally enforceable permit condition is in place that limits the sulfur content of the oil. If this alternative is chosen, the fuel-specific SO_2 emission rate in lb/mmBtu shall be calculated by multiplying the fuel sulfur content limit (weight percent sulfur) by 1.01. In addition, the owner or operator shall periodically determine the sulfur content of the oil combusted in the unit, using one of the oil sampling and analysis options described in section 2.2 of appendix D to this part, and shall keep records of these fuel sampling results in a format suitable for inspection and auditing. Alternatively, the required oil sampling and associated recordkeeping may be performed using a consensus standard (e.g., ASTM, API, etc.) that is prescribed in the unit's Federally-enforceable operating permit, in an applicable State regulation, or in another applicable Federal regulation. If the unit combusts gaseous fuel(s) other than natural gas, the owner or operator shall use the procedures in section 2.3.6 of appendix D to this part to document the total sulfur content of each such fuel and to determine the appropriate default SO2 emission rate for each such fuel.

* * * * *

(iv) * * *

(A) * * *

(*3*) Do not correct the NO_X concentration to 15% O_2.

* * * * *

(I) * * *

(*3*) The initial appendix E testing may be performed at a single load, between 75 and 100 percent of the maximum sustainable load defined in the monitoring plan for the unit, if the average annual capacity factor of the LME unit, when calculated according to the definition of "capacity factor" in § 72.2 of this chapter, is 2.5 percent or less for the three calendar years immediately preceding the year of the testing, and that the annual capacity factor does not exceed 4.0 percent in any of those three years. Similarly, for a LME unit that reports emissions data on an ozone season-only basis, the initial appendix E testing may be performed at a single load between 75 and 100 percent of the maximum sustainable load if the 2.5 and 4.0 percent capacity factor requirements are met for the three ozone seasons immediately preceding the date of the emission testing (see § 75.74(c)(11)). For a group of identical LME units, any unit(s) in the group that meet the 2.5 and 4.0 percent capacity factor requirements may perform the initial appendix E testing at a single load between 75 and 100 percent of the maximum sustainable load.

(*4*) The retest of any LME unit may be performed at a single load between 75 and 100 percent of the maximum sustainable load if, for the three calendar years immediately preceding the year of the retest (or, if applicable, the three ozone seasons immediately preceding the date of the retest), the applicable capacity factor requirements described in paragraph (c)(1)(iv)(I)(*3*) of this section are met.

(*5*) Alternatively, for combustion turbines, the single-load testing described in paragraphs (c)(1)(iv)(I)(*3*) and (c)(1)(iv)(I)(*4*) of this section may be performed at the highest attainable load level corresponding to the season of the year in which the testing is conducted.

(*6*) In all cases where the alternative single-load testing option described in paragraphs (c)(1)(iv)(I)(*3*) through (c)(1)(iv)(I)(*5*) of this section is used, the owner or operator shall keep records documenting that the required capacity factor requirements were met.

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(3) * * *

(ii) * * *

(B) * * *

(*2*) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3-Tank Gauging, Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005; Section 1B-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001; Section 2-Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, First Edition, August 1995 (Reaffirmed March 2006); Section 3-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996 (Reaffirmed, March 2001); Section 4-Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, First Edition April 1995 (Reaffirmed, September 2000); and Section 5-Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, First Edition March 1997 (Reaffirmed, March 2003); for § 75.19; Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992) (all incorporated by reference under § 75.6 of this part); or

* * * * *

(H) For each low mass emissions unit or each low mass emissions unit in a group of identical units, the owner or operator shall determine the cumulative quarterly unit load in megawatt hours or thousands of pounds of steam. The quarterly cumulative unit load shall be the sum of the hourly unit load values recorded under paragraph (c)(2) of this section and shall be determined using Equations LM–5 or LM–6. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly cumulative load for the second calendar quarter of the year shall include only the unit loads for the months of May and June.

$$MW_{qtr} = \sum_{all-hours} MW \qquad \text{Eq. LM-5 (for MW output)}$$

$$ST_{qtr} = \sum_{all-hours} ST \qquad \text{Eq. LM-6 (for steam output)}$$

Where:

MW_{qtr} = Sum of all unit operating loads recorded during the quarter by the unit (MWh).

$ST_{fuel-qtr}$ = Sum of all hourly steam loads recorded during the quarter by the unit (klb of steam/hr).

MW = Unit operating load for a particular unit operating hour (MWh).

ST = Unit steam load for a particular unit operating hour (klb of steam).

* * * * *

(4) * * *

(ii) NO_X mass emissions and NO_X emission rate.

(D) The quarterly and cumulative NO_X emission rate in lb/mmBtu (if required by the applicable program(s)) shall be determined as follows. Calculate the quarterly NO_X emission rate by taking the arithmetic average of all of the hourly EF_{NO_X} values. Calculate the cumulative (year-to-date) NO_X emission rate by taking the arithmetic average of the quarterly NO_X emission rates.

* * * * *

■ 14. Section 75.20 is amended by:

■ a. Adding a new sentence after the third sentence of paragraph (b) introductory text;

■ b. Revising paragraph (c)(1)(v); and

■ c. Removing paragraphs (f)(1) and (f)(2).

The revisions and additions read as follows:

§ 75.20 Initial certification and recertification procedures.

* * * * *

(b) * * * The owner or operator shall also recertify the continuous emission monitoring systems for a unit that has recommenced commercial operation following a period of long-term cold storage as defined in § 72.2 of this chapter. * * *

* * * * *

(c) * * *

(1) * * *

(v) A cycle time test, (where, for the NO_X-diluent continuous emission monitoring system, the test is performed separately on the NO_X pollutant concentration monitor and the diluent gas monitor); and

* * * * *

§ 75.21 [Amended]

■ 15. Section 75.21 is amended by removing the words "or (e)(2)" at the end of the first sentence of paragraph (a)(4).

■ 16. Section 75.22 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Revising paragraphs (a)(5), (a)(6), and (a)(7);

■ c. Revising paragraph (b) introductory text;

■ d. Removing the word "and" at the end of paragraph (b)(3);

■ e. Revising paragraph (b)(5);

■ f. Adding paragraphs (b)(6), (b)(7), and (b)(8); and

■ g. Revising paragraph (c)(1) introductory text.

The revisions and additions read as follows:

§ 75.22 Reference test methods.

(a) The owner or operator shall use the following methods, which are found in appendix A–4 to part 60 of this chapter or have been published by ASTM, to conduct the following tests: monitoring system tests for certification or recertification of continuous emission monitoring systems and excepted monitoring systems under appendix E to this part; the emission tests required under § 75.81(c) and (d); and required quality assurance and quality control tests:

* * * * *

(5) Methods 6, 6A, 6B or 6C, and 7, 7A, 7C, 7D or 7E in appendix A–4 to part 60 of this chapter, as applicable, are the reference methods for determining SO_2 and NO_X pollutant concentrations. (Methods 6A and 6B in appendix A–4 to part 60 of this chapter may also be used to determine SO_2 emission rate in lb/mmBtu.) Methods 7, 7A, 7C, 7D, or 7E in appendix A–4 to part 60 of this chapter must be used to measure total NO_X emissions, both NO and NO_2, for purposes of this part. The owner or operator shall not use the following sections, exceptions, and options of method 7E in appendix A–4 to part 60 of this chapter:

(i) Section 7.1 of the method allowing for use of prepared calibration gas mixtures that are produced in accordance with method 205 in Appendix M of 40 CFR Part 51;

(ii) The sampling point selection procedures in section 8.1 of the method, for the emission testing of boilers and combustion turbines under appendix E to this part. The number and location of the sampling points for those applications shall be as specified in sections 2.1.2.1 and 2.1.2.2 of appendix E to this part;

(iii) Paragraph (3) in section 8.4 of the method allowing for the use of a multi-hole probe to satisfy the multipoint traverse requirement of the method;

(iv) Section 8.6 of the method allowing for the use of "Dynamic Spiking" as an alternative to the interference and system bias checks of the method. Dynamic spiking may be conducted (optionally) as an additional quality assurance check.

(6) Method 3A in appendix A–2 and method 7E in appendix A–4 to part 60 of this chapter are the reference methods for determining NO_X and diluent emissions from stationary gas turbines for testing under appendix E to this part.

(7) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method) (incorporated by reference under § 75.6 of this part) is the reference method for determining Hg concentration.

(i) Alternatively, Method 29 in appendix A–8 to part 60 of this chapter may be used, with these caveats: The procedures for preparation of Hg standards and sample analysis in sections 13.4.1.1 through 13.4.1.3 ASTM D6784–02 (incorporated by reference under § 75.6 of this part) shall be followed instead of the procedures in sections 7.5.33 and 11.1.3 of Method 29 in appendix A–8 to part 60 of this chapter, and the QA/QC procedures in section 13.4.2 of ASTM D6784–02 (incorporated by reference under § 75.6 of this part) shall be performed instead of the procedures in section 9.2.3 of Method 29 in appendix A–8 to part 60 of this chapter. The tester may also opt to use the sample recovery and preparation procedures in ASTM D6784–02 (incorporated by reference under § 75.6 of this part) instead of the Method 29 in appendix A–8 to part 60 of this chapter procedures, as follows: sections 8.2.8 and 8.2.9.1 of Method 29 in appendix A–8 to part 60 of this chapter may be replaced with sections 13.2.9.1 through 13.2.9.3 of ASTM D6784–02 (incorporated by reference under § 75.6 of this part); sections 8.2.9.2 and 8.2.9.3 of Method 29 in appendix A–8 to part 60 of this chapter may be replaced with sections 13.2.10.1 through 13.2.10.4 of ASTM D6784–02 (incorporated by reference under § 75.6 of this part); section 8.3.4 of Method 29 in appendix A–8 to part 60 of this chapter may be replaced with section 13.3.4 or 13.3.6 of ASTM D6784–02 (as appropriate) (incorporated by reference under § 75.6 of this part); and section 8.3.5 of Method 29 in appendix A–8 to part 60 of this chapter may be replaced with section 13.3.5 or 13.3.6 of ASTM D6784–02 (as appropriate) (incorporated by reference under § 75.6 of this part).

(ii) Whenever ASTM D6784–02 (incorporated by reference under § 75.6 of this part) or Method 29 in appendix A–8 to part 60 of this chapter is used, paired sampling trains are required. To validate a RATA run or an emission test run, the relative deviation (RD), calculated according to section 11.7 of appendix K to this part, must not exceed 10 percent, when the average concentration is greater than 1.0 μg/m³. If the average concentration is ≤1.0 μg/m³, the RD must not exceed 20 percent. The RD results are also acceptable if the absolute difference between the Hg concentrations measured by the paired trains does not exceed 0.03 μg/m³. If the RD criterion is met, the run is valid. For each valid run, average the Hg concentrations measured by the two trains (vapor phase, only).

(iii) Two additional reference methods that may be used to measure Hg concentration are: Method 30A, "Determination of Total Vapor Phase Mercury Emissions from Stationary Sources (Instrumental Analyzer Procedure)" and Method 30B, "Determination of Total Vapor Phase Mercury Emissions from Coal-Fired Combustion Sources Using Carbon Sorbent Traps".

(iv) When Method 29 in appendix A–8 to part 60 of this chapter or ASTM D6784–02 (incorporated by reference under § 75.6 of this part) is used for the Hg emission testing required under §§ 75.81(c) and (d), locate the reference method test points according to section 8.1 of Method 30A, and if Hg stratification testing is part of the test protocol, follow the procedures in sections 8.1.3 through 8.1.3.5 of Method 30A.

(b) The owner or operator may use any of the following methods, which are found in appendix A to part 60 of this chapter or have been published by ASTM, as a reference method backup monitoring system to provide quality-assured monitor data:

* * * * *

(5) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method) (incorporated by reference under § 75.6 of this part) for determining Hg concentration;

(6) Method 29 in appendix A–8 to part 60 of this chapter for determining Hg concentration;

(7) Method 30A for determining Hg concentration; and

(8) Method 30B for determining Hg concentration.

(c)(1) Instrumental EPA Reference Methods 3A, 6C, and 7E in appendices A–2 and A–4 of part 60 of this chapter shall be conducted using calibration gases as defined in section 5 of appendix A to this part. Otherwise, performance tests shall be conducted and data reduced in accordance with the test methods and procedures of this part unless the Administrator:

* * * * *

■ 17. Section 75.31 is amended by adding a sentence to the end of paragraph (c)(3) to read as follows:

§ 75.31 Initial missing data procedures.

* * * * *

(c) * * *

(3) * * * Alternatively, where a unit with add-on NO_X emission controls can demonstrate that the controls are operating properly during the hour, as provided in § 75.34(d), the owner or operator may substitute, as applicable, the maximum controlled NO_X emission rate (MCR) or the maximum expected NO_X concentration (MEC).

* * * * *

■ 18. Section 75.32 is amended by revising paragraph (b) to read as follows:

§ 75.32 Determination of monitor data availability for standard missing data procedures.

* * * * *

(b) The monitor data availability shall be calculated for each hour during each missing data period. The owner or operator shall record the percent monitor data availability for each hour of each missing data period to implement the missing data substitution procedures.

* * * * *

■ 19. Section 75.33 is amended by:

■ a. Revising the section heading;

■ b. Removing the word "Whenever" and adding in its place the word "If", and by removing the words "each hour of each" and adding in its place the words "that hour of the", in paragraph (b)(1) introductory text;

■ c. Removing the word "Whenever" and adding in its place the word "If", and by removing the words "each hour of each" and adding in its place the words "that hour of the", in paragraph (b)(2) introductory text;

■ d. Removing the word "Whenever" and adding in its place the word "If", and by removing the word "each" and adding in its place the words "that hour of the", in paragraphs (b)(3) and (b)(4);

■ e. Removing the word "Whenever" and adding in its place the word "If", and by removing the words "each hour of each" and adding in its place the words "that hour of the", in paragraphs (c)(1) introductory text, (c)(2) introductory text, (c)(3), and (c)(4);

■ f. Revising paragraph (c)(8)(iii);

■ g. Revising Tables 1 and 2 in paragraph (c)(8)(iv);

■ h. Removing the word "Whenever" and adding in its place the word "If", and by removing the words "each hour of each" and adding in its place the words "that hour of the", in paragraphs (d)(1) introductory text, (d)(2) introductory text, (d)(3) introductory text, and (d)(4) introductory text.

■ i. Revising Table 3 in paragraph (e)(3); and

The revisions and additions read as follows:

§ 75.33 Standard missing data procedures for SO_2, NO_X, Hg, and flow rate.

* * * * *

(c) * * *

(8) * * *

(iii) For the purposes of providing substitute data under paragraph (c)(4) of this section, a separate, fuel-specific maximum potential concentration (MPC), maximum potential NO_X emission rate (MER), or maximum potential flow rate (MPF) value (as applicable) shall be determined for each type of fuel combusted in the unit, in a manner consistent with § 72.2 of this chapter and with section 2.1.2.1 or 2.1.4.1 of appendix A to this part. For co-firing, the MPC, MER or MPF value shall be based on the fuel with the highest emission rate or flow rate (as applicable). Furthermore, for a unit with add-on NO_X emission controls, a separate fuel-specific maximum controlled NO_X emission rate (MCR) or maximum expected NO_X concentration (MEC) value (as applicable) shall be determined for each type of fuel combusted in the unit. The exact methodology used to determine each fuel-specific MPC, MER, MEC, MCR or MPF value shall be documented in the monitoring plan for the unit or stack.

(iv) * * *

TABLE 1.—MISSING DATA PROCEDURE FOR SO_2 CEMS, CO_2 CEMS, MOISTURE CEMS, HG CEMS, AND DILUENT (CO_2 OR O_2) MONITORS FOR HEAT INPUT DETERMINATION

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours)[2]	Method	Lookback period
95 or more (90 or more for Hg)	N ≤ 24	Average	HB/HA.
	N > 24	For SO_2, CO_2, Hg, and H_2O**, the greater of:	
		Average	HB/HA.
		90th percentile	720 hours.*
		For O_2 and H_2O^X, the lesser of:	
		10th percentile	HB/HA.
			720 hours.*
90 or more, but below 95 (> 80 but < 90 for Hg)	N ≤ 8	Average	HB/HA.
	N > 8	For SO_2, CO_2, Hg, and H_2O**, the greater of:	
		Average	HB/HA.
		95th percentile	720 hours.*
		For O_2 and H_2O^X, the lesser of:	
		Average	HB/HA.
		5th Percentile	720 hours.*
80 or more, but below 90 (> 70 but < 80 for Hg)	N > 0	For SO_2, CO_2, Hg, and H_2O:**	
		Maximum value[1]	720 hours.*
		For O_2 and H_2O^X:	
		Minimum value[1]	720 hours.*
Below 80 (Below 70 for Hg)	N > 0	Maximum potential concentration[3] or % (for SO_2, CO_2, Hg, and H_2O**) *or*	
		Minimum potential concentration or % (for O_2 and H_2O^X).	None.

HB/HA = hour before and hour after the CEMS outage.

*Quality-assured, monitor operating hours, during unit operation. May be either fuel-specific or non-fuel-specific. For units that report data only for the ozone season, include only quality assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than 3 years prior to the missing data period.

[1] Where a unit with add-on SO_2 or Hg emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled concentration from the previous 720 quality-assured monitor operating hours.

[2] During unit operating hours.

[3] Alternatively, where a unit with add-on SO_2 or Hg emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may report the greater of: (a) the maximum expected SO_2 or Hg concentration or (b) 1.25 times the maximum controlled value from the previous 720 quality-assured monitor operating hours.

[X] Use this algorithm for moisture except when Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A–7 to part 60 of this chapter is used for NO_X emission rate.

** Use this algorithm for moisture *only* when Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A–7 to part 60 of this chapter is used for NO_X emission rate.

TABLE 2.—LOAD-BASED MISSING DATA PROCEDURE FOR NO_X-DILUENT CEMS, NO_X CONCENTRATION CEMS AND FLOW RATE CEMS

Trigger conditions		Calculation routines		
Monitor data availability (percent)	Duration (N) of CEMS outage (hours)[2]	Method	Lookback period	Load ranges
95 or more	N ≤ 24	Average	2,160 hours*	Yes.
	N > 24	The greater of:		
		Average	HB/HA	No.
		90th percentile	2,160 hours*	Yes.
90 or more, but below 95	N ≤ 8	Average	2,160 hours*	Yes.
	N > 8	The greater of:		
		Average	HB/HA	No.
		95th percentile	2,160 hours*	Yes.
80 or more, but below 90	N > 0	Maximum value[1]	2,160 hours*	Yes.

TABLE 2.—LOAD-BASED MISSING DATA PROCEDURE FOR NO_X-DILUENT CEMS, NO_X CONCENTRATION CEMS AND FLOW RATE CEMS—Continued

Trigger conditions		Calculation routines		
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) [2]	Method	Lookback period	Load ranges
Below 80	N > 0	Maximum potential NO_X emission rate [3]; or maximum potential NO_X concentration [3]; or maximum potential flow rate.	None	No.

HB/HA = hour before and hour after the CEMS outage.

*Quality-assured, monitor operating hours, using data at the corresponding load range ("load bin") for each hour of the missing data period. May be either fuel-specific or non-fuel-specific. For units that report data only for the ozone season, include only quality assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than three years prior to the missing data period.

[1] Where a unit with add-on NO_X emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled NO_X concentration or emission rate from the previous 2,160 quality-assured monitor operating hours. Units with add-on controls that report NO_X mass emissions on a year-round basis under subpart H of this part may use separate ozone season and non-ozone season data pools to provide substitute data values, as described in § 75.34(a)(2).

[2] During unit operating hours.

[3] Alternatively, where a unit with add-on NO_X emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may report the greater of: (a) the maximum expected NO_X concentration (or maximum controlled NO_X emission rate, as applicable); or (b) 1.25 times the maximum controlled value at the corresponding load bin, from the previous 2,160 quality-assured monitor operating hours.

* * * * *

(e) * * *

(3) * * *

TABLE 3.—NON-LOAD-BASED MISSING DATA PROCEDURE FOR NO_X-DILUENT CEMS AND NO_X CONCENTRATION CEMS

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) [1]	Method	Lookback period
95 or more	$N \leq 24$	Average	2,160 hours.*
	$N > 24$	90th percentile	2,160 hours.*
90 or more, but below 95	$N \leq 8$	Average	2,160 hours.*
	$N > 8$	95th percentile	2,160 hours.*
80 or more, but below 90	$N > 0$	Maximum value [3]	2,160 hours.*
Below 80, or operational bin indeterminable	$N > 0$	Maximum potential NO_X emission rate [2] or maximum potential NO_X concentration [2].	None.

*If operational bins are used, the lookback period is 2,160 quality-assured, monitor operating hours, and data at the corresponding operational bin are used to provide substitute data values. If operational bins are not used, the lookback period is the previous 2,160 quality-assured monitor operating hours. For units that report data only for the ozone season, include only quality-assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than three years prior to the missing data period.

[1] During unit operation.

[2] Alternatively, where a unit with add-on NO_X emission controls can demonstrate that the controls are operating properly, as provided in § 75.34, the unit may report the greater of: (a) the maximum expected NO_X concentration, (or maximum controlled NO_X emission rate, as applicable); or (b) 1.25 times the maximum controlled value at the corresponding operational bin (if applicable), from the previous 2,160 quality-assured monitor operating hours.

[3] Where a unit with add-on NO_X emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled NO_X concentration or emission rate from the previous 2,160 quality-assured monitor operating hours. Units with add-on controls that report NO_X mass emissions on a year-round basis under subpart H of this part may use separate ozone season and non-ozone season data pools to provide substitute data values, as described in § 75.34(a)(2).

* * * * *

■ 20. Section 75.34 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. In paragraph (a)(2)(ii) by removing the words "and (c)(3)" and adding in its place the words ", (c)(3) and (c)(5) of this section, and § 75.38(c),"

■ c. Revising paragraph (a)(3);

■ d. Adding paragraph (a)(5); and

■ e. In paragraph (d) by removing the words "paragraphs (a)(1) and (a)(3) of this section," and adding in its place the words "paragraphs (a)(1), (a)(3) and (a)(5) of this section; and §§ 75.31(c)(3), 75.38(c), and 75.72(c)(3),".

The revisions and additions read as follows:

§ 75.34 Units with add-on emission controls.

(a) The owner or operator of an affected unit equipped with add-on SO_2 and/or NO_X emission controls shall provide substitute data in accordance with paragraphs (a)(1), through (a)(5) of this section for each hour in which quality-assured data from the outlet SO_2 and/or NO_X monitoring system(s) are not obtained.

* * * * *

(3) For each missing data hour in which the percent monitor data availability for SO_2 or NO_X, calculated in accordance with § 75.32, is less than 90.0 percent and is greater than or equal to 80.0 percent; and parametric data establishes that the add-on emission controls were operating properly (*i.e.* within the range of operating parameters provided in the quality assurance/

quality control program) during the hour, the owner or operator may:

(i) Replace the maximum SO_2 concentration recorded in the 720 quality-assured monitor operating hours immediately preceding the missing data period, with the maximum controlled SO2 concentration recorded in the previous 720 quality-assured monitor operating hours; or

(ii) Replace the maximum NO_X concentration(s) or NO_X emission rate(s) from the appropriate load bin(s) (based on a lookback through the 2,160 quality-assured monitor operating hours immediately preceding the missing data period), with the maximum controlled NO_X concentration(s) or emission rate(s) from the appropriate load bin(s) in the same 2,160 quality-assured monitor operating hour lookback period.

* * * * *

(5) For each missing data hour in which the percent monitor data availability for SO_2 or NO_X, calculated in accordance with § 75.32, is below 80.0 percent and parametric data establish that the add-on emission controls were operating properly (*i.e.* within the range of operating parameters provided in the quality assurance/quality control program),in lieu of reporting the maximum potential value, the owner or operator may substitute, as applicable, the greater of:

(i) The maximum expected SO_2 concentration or 1.25 times the maximum hourly controlled SO_2 concentration recorded in the previous 720 quality-assured monitor operating hours;

(ii) The maximum expected NO_X concentration or 1.25 times the maximum hourly controlled NO_X concentration recorded in the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin;

(iii) The maximum controlled hourly NO_X emission rate (MCR) or 1.25 times the maximum hourly controlled NO_X emission rate recorded in the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin;

(iv) For the purposes of implementing the missing data options in paragraphs (a)(5)(i) through (a)(5)(iii) of this section, the maximum expected SO_2 and NO_X concentrations shall be determined, respectively, according to sections 2.1.1.2 and 2.1.2.2 of appendix A to this part. The MCR shall be calculated according to the basic procedure described in section 2.1.2.1(b) of appendix A to this part, except that the words "maximum potential NO_X emission rate (MER)" shall be replaced with the words "maximum controlled NO_X emission rate (MCR)" and the NO_X MEC shall be used instead of the NO_X MPC.

* * * * *

■ 20. Section 75.38 is amended by revising paragraphs (a) and (c) to read as follows.

§ 75.38 Standard missing data procedures for Hg CEMS.

(a) Once 720 quality assured monitor operating hours of Hg concentration data have been obtained following initial certification, the owner or operator shall provide substitute data for Hg concentration in accordance with the procedures in (75.33(b)(1) through (b)(4), except that the term "Hg concentration" shall apply rather than "SO_2 concentration," the term "Hg concentration monitoring system" shall apply rather than "SO_2 pollutant concentration monitor," the term "maximum potential Hg concentration, as defined in section 2.1.7 of appendix A to this part" shall apply, rather than "maximum potential SO_2 concentration", and the percent monitor data availability trigger conditions prescribed for Hg in Table 1 of § 75.33 shall apply rather than the trigger conditions prescribed for SO_2.

* * * * *

(c) For units with FGD systems or add-on Hg emission controls, when the percent monitor data availability is less than 80.0 percent and is greater than or equal to 70.0 percent, and a missing data period occurs, consistent with § 75.34(a)(3), for each missing data hour in which the FGD or Hg emission controls are documented to be operating properly, the owner or operator may report the maximum controlled Hg concentration recorded in the previous 720 quality-assured monitor operating hours. In addition, when the percent monitor data availability is less than 70.0 percent and a missing data period occurs, consistent with § 75.34(a)(5), for each missing data hour in which the FGD or Hg emission controls are documented to be operating properly, the owner or operator may report the greater of the maximum expected Hg concentration (MEC) or 1.25 times the maximum controlled Hg concentration recorded in the previous 720 quality-assured monitor operating hours. The MEC shall be determined in accordance with section 2.1.7.1 of appendix A to this part.

■ 21. Section 75.39 is amended by:

■ a. Revising paragraph (a);

■ b. Revising paragraph (b);

■ c. Revising paragraph (c);

■ d. Revising paragraph (d); and

■ e. Adding paragraph (f).

The revisions and additions read as follows:

§ 75.39 Missing data procedures for sorbent trap monitoring systems.

(a) If a primary sorbent trap monitoring system has not been certified by the applicable compliance date specified under a State or Federal Hg mass emission reduction program that adopts the requirements of subpart I of this part, and if quality-assured Hg concentration data from a certified backup Hg monitoring system, reference method, or approved alternative monitoring system are unavailable, the owner or operator shall report the maximum potential Hg concentration, as defined in section 2.1.7 of appendix A to this part, until the primary system is certified.

(b) For a certified sorbent trap system, a missing data period will occur in the following circumstances, unless quality-assured Hg concentration data from a certified backup Hg CEMS, sorbent trap system, reference method, or approved alternative monitoring system are available:

(1) A gas sample is not extracted from the stack during unit operation (e.g., during a monitoring system malfunction or when the system undergoes maintenance); or

(2) The results of the Hg analysis for the paired sorbent traps are missing or invalid (as determined using the quality assurance procedures in appendix K to this part). The missing data period begins with the hour in which the paired sorbent traps for which the Hg analysis is missing or invalid were put into service. The missing data period ends at the first hour in which valid Hg concentration data are obtained with another pair of sorbent traps (i.e., the hour at which this pair of traps was placed in service), or with a certified backup Hg CEMS, reference method, or approved alternative monitoring system.

(c) *Initial missing data procedures.* Use the missing data procedures in § 75.31(b) until 720 hours of quality-assured Hg concentration data have been collected with the sorbent trap monitoring system(s), following initial certification.

(d) *Standard missing data procedures.* Once 720 quality-assured hours of data have been obtained with the sorbent trap system(s), begin reporting the percent monitor data availability in accordance with § 75.32 and switch from the initial missing data procedures in paragraph (c) of this section to the standard missing data procedures in § 75.38.

* * * * *

(f) In cases where the owner or operator elects to use a primary Hg CEMS and a certified redundant (or non-redundant) backup sorbent trap monitoring system (or vice-versa), when both the primary and backup monitoring systems are out-of-service and quality-assured Hg concentration data from a temporary like-kind replacement analyzer, reference method, or approved alternative monitoring system are unavailable, the previous 720 quality-assured monitor operating hours reported in the electronic quarterly report under § 75.64 shall be used for the required missing data lookback, irrespective of whether these data were recorded by the Hg CEMS, the sorbent trap system, a temporary like-kind replacement analyzer, a reference method, or an approved alternative monitoring system.

■ 22. Section 75.53 is amended by:
■ a. Revising paragraph (a)(1);
■ b. Removing the phrase "(d) or (f)" and adding in its place the phrase "(f) or (h)" in the second sentence of paragraph (a)(2);
■ c. Adding paragraph (e)(1)(xiv); and
■ d. Adding paragraphs (g) and (h).

The revisions and additions read as follows:

§ 75.53 Monitoring plan.

(a) * * *

(1) The provisions of paragraphs (e) and (f) of this section shall be met through December 31, 2008. The owner or operator shall meet the requirements of paragraphs (a), (b), (e), and (f) of this section through December 31, 2008, except as otherwise provided in paragraph (g) of this section. On and after January 1, 2009, the owner or operator shall meet the requirements of paragraphs (a), (b), (g), and (h) of this section only. In addition, the provisions in paragraphs (g) and (h) of this section that support a regulatory option provided in another section of this part must be followed if the regulatory option is used prior to January 1, 2009.

* * * * *

(e) * * *

(1) * * *

(xiv) For each unit with a flow monitor installed on a rectangular stack or duct, if a wall effects adjustment factor (WAF) is determined and applied to the hourly flow rate data:

(A) Stack or duct width at the test location, ft;

(B) Stack or duct depth at the test location, ft;

(C) Wall effects adjustment factor (WAF), to the nearest 0.0001;

(D) Method of determining the WAF;

(E) WAF Effective date and hour;

(F) WAF no longer effective date and hour (if applicable);

(G) WAF determination date;

(H) Number of WAF test runs;

(I) Number of Method 1 traverse points in the WAF test;

(J) Number of test ports in the WAF test; and

(K) Number of Method 1 traverse points in the reference flow RATA.

* * * * *

(g) *Contents of the monitoring plan.* The requirements of paragraphs (g) and (h) of this section shall be met on and after January 1, 2009. Notwithstanding this requirement, the provisions of paragraphs (g) and (h) of this section may be implemented prior to January 1, 2009, as follows. In 2008, the owner or operator may opt to record and report the monitoring plan information in paragraphs (g) and (h) of this section, in lieu of recording and reporting the information in paragraphs (e) and (f) of this section. Each monitoring plan shall contain the information in paragraph (g)(1) of this section in electronic format and the information in paragraph (g)(2) of this section in hardcopy format. Electronic storage of all monitoring plan information, including the hardcopy portions, is permissible provided that a paper copy of the information can be furnished upon request for audit purposes.

(1) *Electronic.* (i) The facility ORISPL number developed by the Department of Energy and used in the National Allowance Data Base (or equivalent facility ID number assigned by EPA, if the facility does not have an ORISPL number). Also provide the following information for each unit and (as applicable) for each common stack and/or pipe, and each multiple stack and/or pipe involved in the monitoring plan:

(A) A representation of the exhaust configuration for the units in the monitoring plan. Provide the ID number of each unit and assign a unique ID number to each common stack, common pipe multiple stack and/or multiple pipe associated with the unit(s) represented in the monitoring plan. For common and multiple stacks and/or pipes, provide the activation date and deactivation date (if applicable) of each stack and/or pipe;

(B) Identification of the monitoring system location(s) (e.g., at the unit-level, on the common stack, at each multiple stack, etc.). Provide an indicator ("flag") if the monitoring location is at a bypass stack or in the ductwork (breeching);

(C) The stack exit height (ft) above ground level and ground level elevation above sea level, and the inside cross-sectional area (ft^2) at the flue exit and at the flow monitoring location (for units with flow monitors, only). Also use appropriate codes to indicate the material(s) of construction and the shape(s) of the stack or duct cross-section(s) at the flue exit and (if applicable) at the flow monitor location;

(D) The type(s) of fuel(s) fired by each unit. Indicate the start and (if applicable) end date of combustion for each type of fuel, and whether the fuel is the primary, secondary, emergency, or startup fuel;

(E) The type(s) of emission controls that are used to reduce SO_2, NO_X, Hg, and particulate emissions from each unit. Also provide the installation date, optimization date, and retirement date (if applicable) of the emission controls, and indicate whether the controls are an original installation;

(F) Maximum hourly heat input capacity of each unit; and

(G) A non-load based unit indicator (if applicable) for units that do not produce electrical or thermal output.

(ii) For each monitored parameter (e.g., SO_2, NO_X, flow, etc.) at each monitoring location, specify the monitoring methodology and the missing data approach for the parameter. If the unmonitored bypass stack approach is used for a particular parameter, indicate this by means of an appropriate code. Provide the activation date/hour, and deactivation date/hour (if applicable) for each monitoring methodology and each missing data approach.

(iii) For each required continuous emission monitoring system, each fuel flowmeter system, each continuous opacity monitoring system, and each sorbent trap monitoring system (as defined in § 72.2 of this chapter), identify and describe the major monitoring components in the monitoring system (e.g., gas analyzer, flow monitor, opacity monitor, moisture sensor, fuel flowmeter, DAHS software, etc.). Other important components in the system (e.g., sample probe, PLC, data logger, etc.) may also be represented in the monitoring plan, if necessary. Provide the following specific information about each component and monitoring system:

(A) For each required monitoring system:

(*1*) Assign a unique, 3-character alphanumeric identification code to the system;

(*2*) Indicate the parameter monitored by the system;

(*3*) Designate the system as a primary, redundant backup, non-redundant backup, data backup, or reference method backup system, as provided in § 75.10(e); and

(*4*) Indicate the system activation date/hour and deactivation date/hour (as applicable).

(B) For each component of each monitoring system represented in the monitoring plan:

(*1*) Assign a unique, 3-character alphanumeric identification code to the component;

(*2*) Indicate the manufacturer, model and serial number;

(*3*) Designate the component type;

(*4*) For dual-span applications, indicate whether the analyzer component ID represents a high measurement scale, a low scale, or a dual range;

(*5*) For gas analyzers, indicate the moisture basis of measurement;

(*6*) Indicate the method of sample acquisition or operation, (e.g., extractive pollutant concentration monitor or thermal flow monitor); and

(*7*) Indicate the component activation date/hour and deactivation date/hour (as applicable).

(iv) Explicit formulas, using the component and system identification codes for the primary monitoring system, and containing all constants and factors required to derive the required mass emissions, emission rates, heat input rates, etc. from the hourly data recorded by the monitoring systems. Formulas using the system and component ID codes for backup monitoring systems are required only if different formulas for the same parameter are used for the primary and backup monitoring systems (e.g., if the primary system measures pollutant concentration on a different moisture basis from the backup system). Provide the equation number or other appropriate code for each emissions formula (e.g., use code F–1 if Equation F–1 in appendix F to this part is used to calculate SO_2 mass emissions). Also identify each emissions formula with a unique three character alphanumeric code. The formula effective start date/hour and inactivation date/hour (as applicable) shall be included for each formula. The owner or operator of a unit for which the optional low mass emissions excepted methodology in § 75.19 is being used is not required to report such formulas.

(v) For each parameter monitored with CEMS, provide the following information:

(A) Measurement scale (high or low);

(B) Maximum potential value (and method of calculation). If NO_X emission rate in lb/mmBtu is monitored, calculate and provide the maximum potential NO_X emission rate in addition to the maximum potential NO_X concentration;

(C) Maximum expected value (if applicable) and method of calculation;

(D) Span value(s) and full-scale measurement range(s);

(E) Daily calibration units of measure;

(F) Effective date/hour, and (if applicable) inactivation date/hour of each span value;

(G) An indication of whether dual spans are required; and

(H) The default high range value (if applicable) and the maximum allowable low-range value for this option.

(vi) If the monitoring system or excepted methodology provides for the use of a constant, assumed, or default value for a parameter under specific circumstances, then include the following information for each such value for each parameter:

(A) Identification of the parameter;

(B) Default, maximum, minimum, or constant value, and units of measure for the value;

(C) Purpose of the value;

(D) Indicator of use, i.e., during controlled hours, uncontrolled hours, or all operating hours;

(E) Type of fuel;

(F) Source of the value;

(G) Value effective date and hour;

(H) Date and hour value is no longer effective (if applicable); and

(I) For units using the excepted methodology under § 75.19, the applicable SO_2 emission factor.

(vii) Unless otherwise specified in section 6.5.2.1 of appendix A to this part, for each unit or common stack on which hardware CEMS are installed:

(A) Maximum hourly gross load (in MW, rounded to the nearest MW, or steam load in 1000 lb/hr (i.e., klb/hr), rounded to the nearest klb/hr, or thermal output in mmBtu/hr, rounded to the nearest mmBtu/hr), for units that produce electrical or thermal output;

(B) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of appendix A to this part), expressed in megawatts, thousands of lb/hr of steam, mmBtu/hr of thermal output, or ft/sec (as applicable);

(C) Except for peaking units, identify the most frequently and second most frequently used load (or operating) levels (i.e., low, mid, or high) in accordance with section 6.5.2.1 of appendix A to this part, expressed in megawatts, thousands of lb/hr of steam, mmBtu/hr of thermal output, or ft/sec (as applicable);

(D) Except for peaking units, an indicator of whether the second most frequently used load (or operating) level is designated as normal in section 6.5.2.1 of appendix A to this part;

(E) The date of the data analysis used to determine the normal load (or operating) level(s) and the two most frequently-used load (or operating) levels (as applicable); and

(F) Activation and deactivation dates and hours, when the maximum hourly gross load, boundaries of the range of operation, normal load (or operating) level(s) or two most frequently-used load (or operating) levels change and are updated.

(viii) For each unit for which CEMS are not installed:

(A) Maximum hourly gross load (in MW, rounded to the nearest MW, or steam load in klb/hr, rounded to the nearest klb/hr, or steam load in mmBtu/hr, rounded to the nearest mmBtu/hr);

(B) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of appendix A to this part), expressed in megawatts, mmBtu/hr of thermal output, or thousands of lb/hr of steam;

(C) Except for peaking units and units using the low mass emissions excepted methodology under § 75.19, identify the load level designated as normal, pursuant to section 6.5.2.1 of appendix A to this part, expressed in megawatts, mmBtu/hr of thermal output, or thousands of lb/hr of steam;

(D) The date of the load analysis used to determine the normal load level (as applicable); and

(E) Activation and deactivation dates and hours, when the maximum hourly gross load, boundaries of the range of operation, or normal load level change and are updated.

(ix) For each unit with a flow monitor installed on a rectangular stack or duct, if a wall effects adjustment factor (WAF) is determined and applied to the hourly flow rate data:

(A) Stack or duct width at the test location, ft;

(B) Stack or duct depth at the test location, ft;

(C) Wall effects adjustment factor (WAF), to the nearest 0.0001;

(D) Method of determining the WAF;

(E) WAF Effective date and hour;

(F) WAF no longer effective date and hour (if applicable);

(G) WAF determination date;

(H) Number of WAF test runs;

(I) Number of Method 1 traverse points in the WAF test;

(J) Number of test ports in the WAF test; and

(K) Number of Method 1 traverse points in the reference flow RATA.

(2) *Hardcopy.* (i) Information, including (as applicable): Identification of the test strategy; protocol for the relative accuracy test audit; other relevant test information; calibration gas levels (percent of span) for the calibration error test and linearity

check; calculations for determining maximum potential concentration, maximum expected concentration (if applicable), maximum potential flow rate, maximum potential NO_X emission rate, and span; and apportionment strategies under §§ 75.10 through 75.18.

(ii) Description of site locations for each monitoring component in the continuous emission or opacity monitoring systems, including schematic diagrams and engineering drawings specified in paragraphs (e)(2)(iv) and (e)(2)(v) of this section and any other documentation that demonstrates each monitor location meets the appropriate siting criteria.

(iii) A data flow diagram denoting the complete information handling path from output signals of CEMS components to final reports.

(iv) For units monitored by a continuous emission or opacity monitoring system, a schematic diagram identifying entire gas handling system from boiler to stack for all affected units, using identification numbers for units, monitoring systems and components, and stacks corresponding to the identification numbers provided in paragraphs (g)(1)(i) and (g)(1)(iii) of this section. The schematic diagram must depict stack height and the height of any monitor locations. Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common stack.

(v) For units monitored by a continuous emission or opacity monitoring system, stack and duct engineering diagrams showing the dimensions and location of fans, turning vanes, air preheaters, monitor components, probes, reference method sampling ports, and other equipment that affects the monitoring system location, performance, or quality control checks.

(h) *Contents of monitoring plan for specific situations.* The following additional information shall be included in the monitoring plan for the specific situations described:

(1) For each gas-fired unit or oil-fired unit for which the owner or operator uses the optional protocol in appendix D to this part for estimating heat input and/or SO_2 mass emissions, or for each gas-fired or oil-fired peaking unit for which the owner/operator uses the optional protocol in appendix E to this part for estimating NO_X emission rate (using a fuel flowmeter), the designated representative shall include the following additional information for each fuel flowmeter system in the monitoring plan:

(i) *Electronic.* (A) Parameter monitored;

(B) Type of fuel measured, maximum fuel flow rate, units of measure, and basis of maximum fuel flow rate (i.e., upper range value or unit maximum) for each fuel flowmeter;

(C) Test method used to check the accuracy of each fuel flowmeter;

(D) Monitoring system identification code;

(E) The method used to demonstrate that the unit qualifies for monthly GCV sampling or for daily or annual fuel sampling for sulfur content, as applicable; and

(F) Activation date/hour and (if applicable) inactivation date/hour for the fuel flowmeter system;

(ii) *Hardcopy.* (A) A schematic diagram identifying the relationship between the unit, all fuel supply lines, the fuel flowmeter(s), and the stack(s). The schematic diagram must depict the installation location of each fuel flowmeter and the fuel sampling location(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe;

(B) For units using the optional default SO_2 emission rate for "pipeline natural gas" or "natural gas" in appendix D to this part, the information on the sulfur content of the gaseous fuel used to demonstrate compliance with either section 2.3.1.4 or 2.3.2.4 of appendix D to this part;

(C) For units using the 720 hour test under 2.3.6 of Appendix D of this part to determine the required sulfur sampling requirements, report the procedures and results of the test; and

(D) For units using the 720 hour test under 2.3.5 of Appendix D of this part to determine the appropriate fuel GCV sampling frequency, report the procedures used and the results of the test.

(2) For each gas-fired peaking unit and oil-fired peaking unit for which the owner or operator uses the optional procedures in appendix E to this part for estimating NO_X emission rate, the designated representative shall include in the monitoring plan:

(i) *Electronic.* Unit operating and capacity factor information demonstrating that the unit qualifies as a peaking unit, as defined in § 72.2 of this chapter for the current calendar year or ozone season, including: capacity factor data for three calendar years (or ozone seasons) as specified in the definition of peaking unit in § 72.2 of this chapter; the method of qualification used; and an indication of whether the data are actual or projected data.

(ii) *Hardcopy.* (A) A protocol containing methods used to perform the baseline or periodic NO_X emission test; and

(B) Unit operating parameters related to NO_X formation by the unit.

(3) For each gas-fired unit and diesel-fired unit or unit with a wet flue gas pollution control system for which the designated representative claims an opacity monitoring exemption under § 75.14, the designated representative shall include in the hardcopy monitoring plan the information specified under § 75.14(b), (c), or (d), demonstrating that the unit qualifies for the exemption.

(4) For each unit using the low mass emissions excepted methodology under § 75.19 the designated representative shall include the following additional information in the monitoring plan that accompanies the initial certification application:

(i) *Electronic.* For each low mass emissions unit, report the results of the analysis performed to qualify as a low mass emissions unit under § 75.19(c). This report will include either the previous three years actual or projected emissions. The following items should be included:

(A) Current calendar year of application;

(B) Type of qualification;

(C) Years one, two, and three;

(D) Annual and/or ozone season measured, estimated or projected NO_X mass emissions for years one, two, and three;

(E) Annual measured, estimated or projected SO_2 mass emissions (if applicable) for years one, two, and three; and

(F) Annual or ozone season operating hours for years one, two, and three.

(ii) *Hardcopy.* (A) A schematic diagram identifying the relationship between the unit, all fuel supply lines and tanks, any fuel flowmeter(s), and the stack(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe;

(B) For units which use the long term fuel flow methodology under § 75.19(c)(3), the designated representative must provide a diagram of the fuel flow to each affected unit or group of units and describe in detail the procedures used to determine the long term fuel flow for a unit or group of units for each fuel combusted by the unit or group of units;

(C) A statement that the unit burns only gaseous fuel(s) and/or fuel oil and a list of the fuels that are burned or a statement that the unit is projected to burn only gaseous fuel(s) and/or fuel oil and a list of the fuels that are projected to be burned;

(D) A statement that the unit meets the applicability requirements in § 75.19(a) and (b); and

(E) Any unit historical actual, estimated and projected emissions data and calculated emissions data demonstrating that the affected unit qualifies as a low mass emissions unit under § 75.19(a) and 75.19(b).

(5) For qualification as a gas-fired unit, as defined in § 72.2 of this part, the designated representative shall include in the monitoring plan, in electronic format, the following: Current calendar year, fuel usage data for three calendar years (or ozone seasons) as specified in the definition of gas-fired in § 72.2 of this part, the method of qualification used, and an indication of whether the data are actual or projected data.

(6) For each monitoring location with a stack flow monitor that is exempt from performing 3-load flow RATAs (peaking units, bypass stacks, or by petition) the designated representative shall include in the monitoring plan an indicator of exemption from 3-load flow RATA using the appropriate exemption code.

■ 23. Section 75.57 is amended by:

■ a. Adding the phrase ", or mmBtu/hr of thermal output, rounded to the nearest mmBtu/hr" after the phrase "rounded to the nearest 1000 lb/hr", in paragraph (b)(3);

■ b. Revising Table 4a in paragraph (c)(4)(iv);

■ c. Removing the word "hundredth" and adding in its place the word "tenth" in paragraph (i)(1)(iv); and

■ d. Removing the words ", § 75.12(b)," from paragraphs (i)(2) and (j)(2).

The revisions read as follows:

§ 75.57 General recordkeeping provisions.

* * * * *

(c) * * *

(4) * * *

(iv) * * *

TABLE 4A.—CODES FOR METHOD OF EMISSIONS AND FLOW DETERMINATION

Code	Hourly emissions/flow measurement or estimation method
1	Certified primary emission/flow monitoring system.
2	Certified backup emission/flow monitoring system.
3	Approved alternative monitoring system.
4	Reference method: SO_2: Method 6C. Flow: Method 2 or its allowable alternatives under appendix A to part 60 of this chapter. NO_X: Method 7E. CO_2 or O_2: Method 3A.
5	For units with add-on SO_2 and/or NO_X emission controls: SO_2 concentration or NO_X emission rate estimate from Agency preapproved parametric monitoring method.
6	Average of the hourly SO_2 concentrations, CO_2 concentrations, O_2 concentrations, NO_X concentrations, flow rates, moisture percentages or NO_X emission rates for the hour before and the hour following a missing data period.
7	Initial missing data procedures used. Either: (a) the average of the hourly SO_2 concentration, CO_2 concentration, O_2 concentration, or moisture percentage for the hour before and the hour following a missing data period; or (b) the arithmetic average of all NO_X concentration, NO_X emission rate, or flow rate values at the corresponding load range (or a higher load range), or at the corresponding operational bin (non-load-based units, only); or (c) the arithmetic average of all previous NO_X concentration, NO_X emission rate, or flow rate values (non-load-based units, only).
8	90th percentile hourly SO_2 concentration, CO_2 concentration, NO_X concentration, flow rate, moisture percentage, or NO_X emission rate or 10th percentile hourly O_2 concentration or moisture percentage in the applicable lookback period (moisture missing data algorithm depends on which equations are used for emissions and heat input).
9	95th percentile hourly SO_2 concentration, CO_2 concentration, NO_X concentration, flow rate, moisture percentage, or NO_X emission rate or 5th percentile hourly O_2 concentration or moisture percentage in the applicable lookback period (moisture missing data algorithm depends on which equations are used for emissions and heat input).
10	Maximum hourly SO_2 concentration, CO_2 concentration, NO_X concentration, flow rate, moisture percentage, or NO_X emission rate or minimum hourly O_2 concentration or moisture percentage in the applicable lookback period (moisture missing data algorithm depends on which equations are used for emissions and heat input).
11	Average of hourly flow rates, NO_X concentrations or NO_X emission rates in corresponding load range, for the applicable lookback period. For non-load-based units, report either the average flow rate, NO_X concentration or NO_X emission rate in the applicable lookback period, or the average flow rate or NO_X value at the corresponding operational bin (if operational bins are used).
12	Maximum potential concentration of SO_2, maximum potential concentration of CO_2, maximum potential concentration of NO_X maximum potential flow rate, maximum potential NO_X emission rate, maximum potential moisture percentage, minimum potential O_2 concentration or minimum potential moisture percentage, as determined using § 72.2 of this chapter and section 2.1 of appendix A to this part (moisture missing data algorithm depends on which equations are used for emissions and heat input).
13	Maximum expected concentration of SO_2, maximum expected concentration of NO_X, maximum expected Hg concentration, or maximum controlled NO_X emission rate. (*See* § 75.34(a)(5)).
14	Diluent cap value (if the cap is replacing a CO_2 measurement, use 5.0 percent for boilers and 1.0 percent for turbines; if it is replacing an O_2 measurement, use 14.0 percent for boilers and 19.0 percent for turbines).
15	1.25 times the maximum hourly controlled SO_2 concentration, Hg concentration, NO_X concentration at the corresponding load or operational bin, or NO_X emission rate at the corresponding load or operational bin, in the applicable lookback period (*See* § 75.34(a)(5)).
16	SO_2 concentration value of 2.0 ppm during hours when only "very low sulfur fuel", as defined in § 72.2 of this chapter, is combusted.
17	Like-kind replacement non-redundant backup analyzer.
19	200 percent of the MPC; default high range value.
20	200 percent of the full-scale range setting (full-scale exceedance of high range).
21	Negative hourly CO_2 concentration, SO_2 concentration, NO_X concentration, percent moisture, or NO_X emission rate replaced with zero.
22	Hourly average SO_2 or NO_X concentration, measured by a certified monitor at the control device inlet (units with add-on emission controls only).
23	Maximum potential SO_2 concentration, NO_X concentration, CO_2 concentration, NO_X emission rate or flow rate, or minimum potential O_2 concentration or moisture percentage, for an hour in which flue gases are discharged through an unmonitored bypass stack.
24	Maximum expected NO_X concentration, or maximum controlled NO_X emission rate for an hour in which flue gases are discharged downstream of the NO_X emission controls through an unmonitored bypass stack, and the add-on NO_X emission controls are confirmed to be operating properly.
25	Maximum potential NO_X emission rate (MER). (Use only when a NO_X concentration full-scale exceedance occurs and the diluent monitor is unavailable.)

TABLE 4A.—CODES FOR METHOD OF EMISSIONS AND FLOW DETERMINATION—Continued

Code	Hourly emissions/flow measurement or estimation method
26	1.0 mmBtu/hr substituted for Heat Input Rate for an operating hour in which the calculated Heat Input Rate is zero or negative.
32	Hourly Hg concentration determined from analysis of a single trap multiplied by a factor of 1.111 when one of the paired traps is invalidated or damaged (*See* Appendix K, section 8).
33	Hourly Hg concentration determined from the trap resulting in the higher Hg concentration when the relative deviation criterion for the paired traps is not met (*See* Appendix K, section 8).
40	Fuel specific default value (or prorated default value) used for the hour.
54	Other quality assured methodologies approved through petition. These hours are included in missing data lookback and are treated as unavailable hours for percent monitor availability calculations.
55	Other substitute data approved through petition. These hours are not included in missing data lookback and are treated as unavailable hours for percent monitor availability calculations.

* * * * *

■ 24. Section 75.58 is amended by:
■ a. Revising paragraph (b)(3) introductory text;
■ b. Removing paragraphs (b)(3)(iii) and (b)(3)(iv);
■ c. Removing the word "and" from paragraph (c)(1)(xii);
■ d. Removing the period and adding in its place a semicolon and adding the word "and" to the end of the paragraph, in paragraph (c)(1)(xiii);
■ e. Adding paragraph (c)(1)(xiv);
■ f. Removing the period and adding in its place a semicolon and adding the word "and" to the end of the paragraph, in paragraph (c)(4)(x);
■ g. Adding paragraph (c)(4)(xi);
■ h. Removing the words "rounded to the nearest hundredth for diesel fuel" and adding in its place the words "rounded to either the nearest hundredth, or nearest ten-thousandth for diesel fuels" in paragraph (c)(5)(ii);
■ i. Removing the word "and" after the semicolon in paragraph (d)(1)(ix).
■ j. Removing the period and adding in its place a semicolon and adding the word "and" to the end of the paragraph, in paragraph (d)(1)(x);
■ k. Adding paragraph (d)(1)(xi);
■ l. Removing the word "and" after the semicolon in paragraph (d)(2)(ix);
■ m. Removing the period and adding in its place a semicolon and adding the word "and" to the end of the paragraph, in paragraph (d)(2)(x);
■ n. Adding paragraph (d)(2)(xi);
■ o. Revising paragraph (f)(1)(iii);
■ p. Removing the word "and" at the end of paragraph (f)(1)(xi);
■ q. Removing the period and adding in its place a semicolon at the end of paragraph (f)(1)(xii);
■ r. Adding paragraphs (f)(1)(xiii) and (f)(1)(xiv); and
■ s. Removing the word "Component" and adding in its place the word "Monitoring", in paragraph (f)(2)(x).

The revisions and additions read as follows:

§ 75.58 General recordkeeping provisions for specific situations.

* * * * *

(b) * * *

(3) Except as otherwise provided in § 75.34(d), for units with add-on SO_2 or NO_X emission controls following the provisions of § 75.34(a)(1), (a)(2), (a)(3) or (a)(5), and for units with add-on Hg emission controls, the owner or operator shall record:

* * * * *

(c) * * *

(1) * * *

(xiv) Heat input formula ID and SO_2 Formula ID (required beginning January 1, 2009).

* * * * *

(4) * * *

(xi) Heat input formula ID and SO_2 Formula ID (required beginning January 1, 2009).

* * * * *

(d) * * *

(1) * * *

(xi) Heat input rate formula ID (required beginning January 1, 2009).

(2) * * *

(xi) Heat input rate formula ID (required beginning January 1, 2009).

* * * * *

(f) * * *

(1) * * *

(iii) Fuel type (pipeline natural gas, natural gas, other gaseous fuel, residual oil, or diesel fuel). If more than one type of fuel is combusted in the hour, either:

(A) Indicate the fuel type which results in the highest emission factors for NO_X (this option is in effect through December 31, 2008); or

(B) Indicate the fuel type resulting in the highest emission factor for each parameter (SO_2, NO_X emission rate, and CO_2) separately (this option is required on and after January 1, 2009);

* * * * *

(xiii) Base or peak load indicator (as applicable); and

(xiv) Multiple fuel flag.

* * * * *

■ 25. Section 75.59 is amended by:
■ a. Adding the phrase "(on and after January 1, 2009, only the component identification code is required)" after the word "code", in paragraph (a)(1)(i);
■ b. Revising paragraph (a)(1)(viii);
■ c. Removing the phrase "For the qualifying test for off-line calibration, the owner or operator shall indicate" and adding in its place the phrase "Indication of", in paragraph (a)(1)(xi);
■ d. Adding the phrase "(after January 1, 2009, only the component identification code is required)" after the word "code", in paragraph (a)(2)(i);
■ e. Adding the phrase "(on and after January 1, 2009, only the component identification code is required)" after the word "code", in paragraph (a)(3)(i);
■ f. Adding the phrase "(only span scale is required on and after January 1, 2009)" after the word "scale", in paragraph (a)(3)(ii);
■ g. Adding the phrase "(on and after January 1, 2009, only the system identification code is required)" after the word "code", in paragraph (a)(4)(i);
■ h. Removing the word "and" after the semicolon at the end of paragraph (a)(4)(vi)(L);
■ i. Removing the period and adding in its place a semicolon and adding the word "and" at the end of paragraph (a)(4)(vi)(M);
■ j. Adding paragraph (a)(4)(vi)(N);
■ k. Removing the word "and" after the semicolon, at the end of paragraph (a)(4)(vii)(K);
■ l. Removing the period and adding in its place a semicolon and adding the word "and" at the end of paragraph (a)(4)(vii)(L);
■ m. Adding paragraph (a)(4)(vii)(M);
■ n. Revising paragraph (a)(6) introductory text;
■ o. Adding the phrase "(on and after January 1, 2009, only the component identification code is required)" after the word "code", in paragraph (a)(6)(i);
■ p. Removing the phrase "Cycle time result for the entire system" and adding in its place the phrase "Total cycle time", in paragraph (a)(6)(ix);
■ q. Revising the heading of reserved paragraph (a)(7)(viii);
■ r. Adding paragraphs (a)(7)(ix) and (a)(7)(x);
■ s. Revising paragraph (a)(8);

■ t. Removing and reserving paragraph (a)(12)(iii);
■ u. Removing the number "(2)" from the paragraph identifier "§ 75.64(a)(2)" in the second sentence of paragraph (a)(13);
■ v. Adding the phrase "(on and after January 1, 2009, only the component identification code is required)" after the word "tested", in paragraphs (b)(1)(ii) and (b)(2)(i);
■ w. Adding the phrase "(on and after January 1, 2009, only the monitoring system identification code is required)" after the word "code", in paragraph (b)(4)(i)(A);
■ x. Removing the word "and" after the semicolon at the end of paragraph (b)(4)(i)(H);
■ y. Removing the period and adding in its place a semicolon and adding the word "and" at the end of paragraph (b)(4)(i)(I);
■ z. Adding paragraph (b)(4)(i)(J);
■ aa. Revising paragraphs (b)(4)(ii)(A), (b)(4)(ii)(B), and (b)(4)(ii)(F);
■ bb. Removing the word "and" after the semicolon at the end of paragraph (b)(4)(ii)(L);
■ cc. Removing the period and adding in its place a semicolon and adding the word "and" at the end of paragraph (b)(4)(ii)(M);
■ dd. Adding paragraph (b)(4)(ii)(N);
■ ee. Adding the phrase "(on and after January 1, 2009, component identification codes shall be reported in addition to the monitoring system identification code)" after the second occurrence of the word "system" in paragraphs (b)(5)(i)(B), (b)(5)(ii)(B), and (b)(5)(iii)(B);
■ ff. Adding the phrase "This requirement remains in effect through December 31, 2008" after the word "run;", in paragraph (b)(5)(i)(H);
■ gg. Adding the phrase "(as applicable). This requirement remains in effect through December 31, 2008" after the word "level", in paragraph (b)(5)(iv)(A);
■ hh. Removing the word "and" after the semicolon at the end of paragraph (b)(5)(iv)(G);
■ ii. Removing the period and adding in its place a semicolon and adding the word "and" at the end of paragraph (b)(5)(iv)(H);
■ jj. Adding paragraph (b)(5)(iv)(I);
■ kk. Removing the word "and" after the semicolon at the end of paragraph (d)(1)(xi);
■ ll. Removing the period and adding in its place a semicolon and adding the word "and" at the end of paragraph (d)(1)(xii);
■ mm. Adding paragraph (d)(1)(xiii);
■ nn. Removing the phrase ", multiplied by 1.15, if appropriate" from paragraph (d)(2)(iii);
■ oo. Removing the word "and" after the semicolon at the end of paragraph (d)(2)(iv);
■ pp. Removing the period and adding in its place a semicolon at the end of paragraph (d)(2)(v); and
■ qq. Adding paragraphs (d)(2)(vi), (d)(2)(vii), (e) and (f).

The revisions and additions read as follows:

§ 75.59 Certification, quality, assurance, and quality control record provisions.

* * * * *

(a) * * *

(1) * * *

(viii) For 7-day calibration error tests, a test number and reason for test;

* * * * *

(4) * * *

(vi) * * *

(N) Test number.

(vii) * * *

(M) An indicator ("flag") if separate reference ratios are calculated for each multiple stack.

* * * * *

(6) For each SO_2, NO_X, Hg, or CO_2 pollutant concentration monitor, each component of a NO_X-diluent continuous emission monitoring system, and each CO_2 or O_2 monitor used to determine heat input, the owner or operator shall record the following information for the cycle time test:

* * * * *

(7) * * *

(viii) Data elements for Methods 30A and 30B. [Reserved]

(ix) For a unit with a flow monitor installed on a rectangular stack or duct, if a site-specific default or measured wall effects adjustment factor (WAF) is used to correct the stack gas volumetric flow rate data to account for velocity decay near the stack or duct wall, the owner or operator shall keep records of the following for each flow RATA performed with EPA Method 2 in appendices A–1 and A–2 to part 60 of this chapter, subsequent to the WAF determination:

(A) Monitoring system ID;

(B) Test number;

(C) Operating level;

(D) RATA end date and time;

(E) Number of Method 1 traverse points; and

(F) Wall effects adjustment factor (WAF), to the nearest 0.0001.

(x) For each RATA run using Method 29 in appendix A–8 to part 60 of this chapter to determine Hg concentration:

(A) Percent CO_2 and O_2 in the stack gas, dry basis;

(B) Moisture content of the stack gas (percent H_2O);

(C) Average stack gas temperature (°F);

(D) Dry gas volume metered (dscm);

(E) Percent isokinetic;

(F) Particulate Hg collected in the front half of the sampling train, corrected for the front-half blank value (μg); and

(G) Total vapor phase Hg collected in the back half of the sampling train, corrected for the back-half blank value (μg).

(8) For each certified continuous emission monitoring system, continuous opacity monitoring system, excepted monitoring system, or alternative monitoring system, the date and description of each event which requires certification, recertification, or certain diagnostic testing of the system and the date and type of each test performed. If the conditional data validation procedures of § 75.20(b)(3) are to be used to validate and report data prior to the completion of the required certification, recertification, or diagnostic testing, the date and hour of the probationary calibration error test shall be reported to mark the beginning of conditional data validation.

* * * * *

(b) * * *

(4) * * *

(i) * * *

(J) Test number.

(ii) * * *

(A) Completion date and hour of most recent primary element inspection or test number of the most recent primary element inspection (as applicable); (on and after January 1, 2009, the test number of the most recent primary element inspection is required in lieu of the completion date and hour for the most recent primary element inspection);

(B) Completion date and hour of most recent flow meter of transmitter accuracy test or test number of the most recent flowmeter or transmitter accuracy test (as applicable); (on and after January 1, 2009, the test number of the most recent flowmeter or transmitter accuracy test is required in lieu of the completion date and hour for the most recent flowmeter or transmitter accuracy test);

* * * * *

(F) Average load, in megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output;

* * * * *

(N) Monitoring system identification code.

* * * * *

(5) * * *

(iv) * * *

(I) Component identification code (required on and after January 1, 2009).

* * * * *

(d) * * *

(1) * * *

(xiii) An indicator ("flag") if the run is used to calculate the highest 3-run average NO_X emission rate at any load level.

(2) * * *

(vi) Indicator of whether the testing was done at base load, peak load or both (if appropriate); and

(vii) The default NO_X emission rate for peak load hours (if applicable).

* * * * *

(e) *Excepted monitoring for Hg low mass emission units under § 75.81(b).* For qualifying coal-fired units using the alternative low mass emission methodology under § 75.81(b), the owner or operator shall record the data elements described in § 75.59(a)(7)(vii), § 75.59(a)(7)(viii), or § 75.59(a)(7)(x), as applicable, for each run of each Hg emission test and re-test required under § 75.81(c)(1) or § 75.81(d)(4)(iii).

(f) *DAHS Verification.* For each DAHS (missing data and formula) verification that is required for initial certification, recertification, or for certain diagnostic testing of a monitoring system, record the date and hour that the DAHS verification is successfully completed. (This requirement only applies to units that report monitoring plan data in accordance with § 75.53(g) and (h).)

* * * * *

■ 26. Section 75.60 is amended by adding paragraph (b)(8) to read as follows:

§ 75.60 General provisions.

* * * * *

(b) * * *

(8) *Routine retest reports for Hg low mass emissions units.* If requested in writing (or by electronic mail) by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy report for a semiannual or annual retest required under § 75.81(d)(4)(iii) for a Hg low mass emissions unit, within 45 days after completing the test or within 15 days of receiving the request, whichever is later. The designated representative shall report, at a minimum, the following hardcopy information to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the hardcopy report: a summary of the test results; the raw reference method data for each test run; the raw data and results of all pretest, post-test, and post-run quality-assurance checks of the reference method; the raw data and results of moisture measurements made during the test runs (if applicable); diagrams illustrating the test and sample point locations; a copy of the test protocol used; calibration certificates for the gas standards or standard solutions used in the testing; laboratory calibrations of the source sampling equipment; and the names of the key personnel involved in the test program, including test team members, plant contact persons, agency representatives and test observers.

* * * * *

■ 27. Section 75.61 is amended by:

■ a. Revising the first sentence of paragraph (a)(1) introductory text;

■ b. Revising paragraph (a)(3);

■ c. Revising the first sentence of paragraph (a)(5) introductory text; and

■ d. Adding paragraphs (a)(7) and (a)(8)

The revisions and additions read as follows:

§ 75.61 Notifications.

(a) * * *

(1) * * * The owner or operator or designated representative for an affected unit shall submit written notification of initial certification tests and revised test dates as specified in § 75.20 for continuous emission monitoring systems, for the excepted Hg monitoring methodology under § 75.81(b), for alternative monitoring systems under subpart E of this part, or for excepted monitoring systems under appendix E to this part, except as provided in paragraphs (a)(1)(iii), (a)(1)(iv) and (a)(4) of this section. * * *

* * * * *

(3) *Unit shutdown and recommencement of commercial operation.* For an affected unit that will be shut down on the relevant compliance date specified in § 75.4 or in a State or Federal pollutant mass emissions reduction program that adopts the monitoring and reporting requirements of this part, if the owner or operator is relying on the provisions in § 75.4(d) to postpone certification testing, the designated representative for the unit shall submit notification of unit shutdown and recommencement of commercial operation as follows:

(i) For planned unit shutdowns (e.g., extended maintenance outages), written notification of the planned shutdown date shall be provided at least 21 days prior to the applicable compliance date, and written notification of the planned date of recommencement of commercial operation shall be provided at least 21 days in advance of unit restart. If the actual shutdown date or the actual date of recommencement of commercial operation differs from the planned date, written notice of the actual date shall be submitted no later than 7 days following the actual date of shutdown or of recommencement of commercial operation, as applicable;

(ii) For unplanned unit shutdowns (e.g., forced outages), written notification of the actual shutdown date shall be provided no more than 7 days after the shutdown, and written notification of the planned date of recommencement of commercial operation shall be provided at least 21 days in advance of unit restart. If the actual date of recommencement of commercial operation differs from the expected date, written notice of the actual date shall be submitted no later than 7 days following the actual date of recommencement of commercial operation.

* * * * *

(5) * * * The owner or operator or designated representative of an affected unit shall submit written notice of the date of periodic relative accuracy testing performed under section 2.3.1 of appendix B to this part, of periodic retesting performed under section 2.2 of appendix E to this part, of periodic retesting of low mass emissions units performed under § 75.19(c)(1)(iv)(D), and of periodic retesting of Hg low mass emissions units performed under § 75.81(d)(4)(iii), no later than 21 days prior to the first scheduled day of testing. * * *

(7) *Long-term cold storage and recommencement of commercial operation.* The designated representative for an affected unit that is placed into long-term cold storage that is relying on the provisions in § 75.4(d) or § 75.64(a), either to postpone certification testing or to discontinue the submittal of quarterly reports during the period of long-term cold storage, shall provide written notification of long-term cold storage status and recommencement of commercial operation as follows:

(i) Whenever an affected unit has been placed into long-term cold storage, written notification of the date and hour that the unit was shutdown and a statement from the designated representative stating that the shutdown is expected to last for at least two years from that date, in accordance with the definition for long-term cold storage of a unit as provided in § 72.2 of this chapter.

(ii) Whenever an affected unit that has been placed into long-term cold storage is expected to resume operation, written notification shall be submitted 45 calendar days prior to the planned date of recommencement of commercial operation. If the actual date of recommencement of commercial operation differs from the expected date, written notice of the actual date shall be submitted no later than 7 days following the actual date of recommencement of commercial operation.

(8) *Certification deadline date for new or newly affected units.* The designated representative of a new or newly affected unit shall provide notification of the date on which the relevant deadline for initial certification is reached, either as provided in § 75.4(b) or § 75.4(c), or as specified in a State or Federal SO_2, NO_X, or Hg mass emission reduction program that incorporates by reference, or otherwise adopts, the monitoring, recordkeeping, and reporting requirements of subpart F, G, H, or I of this part. The notification shall be submitted no later than 7 calendar days after the applicable certification deadline is reached.

* * * * *

■ 28. Section 75.62 is amended by:

■ a. Revising paragraph (a)(1); and

■ b. Removing the number "45" and adding in its place the number "21" before the phrase "days prior", in paragraph (a)(2).

The revisions read as follows:

§ 75.62 Monitoring plan submittals.

(a) * * *

(1) *Electronic.* Using the format specified in paragraph (c) of this section, the designated representative for an affected unit shall submit a complete, electronic, up-to-date monitoring plan file (except for hardcopy portions identified in paragraph (a)(2) of this section) to the Administrator as follows: no later than 21 days prior to the initial certification tests; at the time of each certification or recertification application submission; and (prior to or concurrent with) the submittal of the electronic quarterly report for a reporting quarter where an update of the electronic monitoring plan information is required, either under § 75.53(b) or elsewhere in this part.

* * * * *

■ 29. Section 75.63 is amended by:

■ a. Removing the phrase "and a hardcopy certification application form (EPA form 7610–14)" from paragraph (a)(1)(i)(A);

■ b. Revising paragraph (a)(1)(ii)(A);

■ c. Adding the phrase "or § 75.53(h)(4)(ii) (as applicable)" after the identifier "§ 75.53(f)(5)(ii)", in paragraph (a)(1)(ii)(B);

■ d. Removing the phrase "and a hardcopy certification application form (EPA form 7610–14)" after the word "section", in paragraph (a)(2)(i);

■ e. Revising paragraph (a)(2)(iii);

■ f. Removing and reserving paragraph (b)(2)(iii);

■ g. Revising paragraph (b)(2)(iv).

The revisions read as follows:

§ 75.63 Initial certification or recertification application.

(a) * * *

(1) * * *

(ii) * * *

(A) To the Administrator, the electronic low mass emission qualification information required by § 75.53(f)(5)(i) or § 75.53(h)(4)(i) (as applicable) and paragraph (b)(1)(i) of this section; and

* * * * *

(2) * * *

(iii) Notwithstanding the requirements of paragraphs (a)(2)(i) and (a)(2)(ii) of this section, for an event for which the Administrator determines that only diagnostic tests (*see* § 75.20(b)) are required rather than recertification testing, no hardcopy submittal is required; however, the results of all diagnostic test(s) shall be submitted prior to or concurrent with the electronic quarterly report required under § 75.64. Notwithstanding the requirement of § 75.59(e), for DAHS (missing data and formula) verifications, no hardcopy submittal is required; the owner or operator shall keep these test results on-site in a format suitable for inspection.

* * * * *

(b) * * *

(2) * * *

(iv) Designated representative signature certifying the accuracy of the submission.

* * * * *

■ 30. Section 75.64 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Redesignate paragraph (a)(2)(xiv) as paragraph (a)(2)(xiii);

■ c. Revise newly designated paragraph (a)(2)(xiii);

■ d. Removing paragraph (a)(8);

■ e. Redesignating paragraphs (a)(9) through (a)(11) as paragraphs (a)(13) through (a)(15), and redesignating paragraphs (a)(3) through (a)(7) as paragraphs (a)(8) through (a)(12);

■ f. Adding new paragraphs (a)(3) through (a)(7); and

■ g. Removing the citation "§ 75.59", and adding in its place "§ 75.58(f)(2)" at the end of newly designated paragraph (a)(14).

The revisions and additions read as follows:

§ 75.64 Quarterly reports.

(a) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in paragraphs (a), (b), and (c) of this section to the Administrator quarterly, beginning with the data from the earlier of the calendar quarter corresponding to the date of provisional certification or the calendar quarter corresponding to the relevant deadline for initial certification in § 75.4(a), (b), or (c). The initial quarterly report shall contain hourly data beginning with the hour of provisional certification or the hour corresponding to the relevant certification deadline, whichever is earlier. For an affected unit subject to § 75.4(d) that is shutdown on the relevant compliance date in § 75.4(a) or has been placed in long-term cold storage (as defined in § 72.2 of this chapter), quarterly reports are not required. In such cases, the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the unit recommences commercial operation (where the initial quarterly report contains hourly data beginning with the first hour of recommenced commercial operation of the unit). For units placed into long-term cold storage during a reporting quarter, the exemption from submitting quarterly reports begins with the calendar quarter following the date that the unit is placed into long-term cold storage. For any provisionally-certified monitoring system, § 75.20(a)(3) shall apply for initial certifications, and § 75.20(b)(5) shall apply for recertifications. Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Prior to January 1, 2008, each electronic report shall include for each affected unit (or group of units using a common stack), the information provided in paragraphs (a)(1), (a)(2), and (a)(8) through (a)(15) of this section. During the time period of January 1, 2008 to January 1, 2009, each electronic report shall include, either the information provided in paragraphs (a)(1), (a)(2), and (a)(8) through (a)(15) of this section or the information provided in paragraphs (a)(3) through (a)(15) of this section. On and after January 1, 2009, the owner or operator shall meet the requirements of paragraphs (a)(3) through (a)(15) of this section only. Each electronic report shall also include the date of report generation.

* * * * *

(2) * * *

(xiii) Supplementary RATA information required under § 75.59(a)(7), except that:

(A) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (i.e., Method 2F or 2G in appendices A–1 and A–2 to part 60 of this chapter), with or without wall effects adjustments;

(B) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;

(C) The data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and

(D) The data under § 75.59(a)(7)(ix)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is applied.

(3) Facility identification information, including:

(i) Facility/ORISPL number;

(ii) Calendar quarter and year for the data contained in the report; and

(iii) Version of the electronic data reporting format used for the report.

(4) In accordance with § 75.62(a)(1), if any monitoring plan information required in § 75.53 requires an update, either under § 75.53(b) or elsewhere in this part, submission of the electronic monitoring plan update shall be completed prior to or concurrent with the submittal of the quarterly electronic data report for the appropriate quarter in which the update is required.

(5) Except for the daily calibration error test data, daily interference check, and off-line calibration demonstration information required in § 75.59(a)(1) and (2), which must always be submitted with the quarterly report, the certification, quality assurance, and quality control information required in § 75.59 shall either be submitted prior to or concurrent with the submittal of the relevant quarterly electronic data report.

(6) The information and hourly data required in §§ 75.57 through 75.59, and daily calibration error test data, daily interference check, and off-line calibration demonstration information required in § 75.59(a)(1) and (2).

(7) Notwithstanding the requirements of paragraphs (a)(4) through (a)(6) of this section, the following information is excluded from electronic reporting:

(i) Descriptions of adjustments, corrective action, and maintenance;

(ii) Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan);

(iii) Opacity data listed in § 75.57(f), and in § 75.59(a)(8);

(iv) For units with SO_2 or NO_X add-on emission controls that do not elect to use the approved site-specific parametric monitoring procedures for calculation of substitute data, the information in § 75.58(b)(3);

(v) Information required by § 75.57(h) concerning the causes of any missing data periods and the actions taken to cure such causes;

(vi) Hardcopy monitoring plan information required by § 75.53 and hardcopy test data and results required by § 75.59;

(vii) Records of flow monitor and moisture monitoring system polynomial equations, coefficients, or "K" factors required by § 75.59(a)(5)(vi) or § 75.59(a)(5)(vii);

(viii) Daily fuel sampling information required by § 75.58(c)(3)(i) for units using assumed values under appendix D of this part;

(ix) Information required by §§ 75.59(b)(1)(vi), (vii), (viii), (ix), and (xiii), and (b)(2)(iii) and (iv) concerning fuel flowmeter accuracy tests and transmitter/transducer accuracy tests;

(x) Stratification test results required as part of the RATA supplementary records under § 75.59(a)(7);

(xi) Data and results of RATAs that are aborted or invalidated due to problems with the reference method or operational problems with the unit and data and results of linearity checks that are aborted or invalidated due to problems unrelated to monitor performance; and

(xii) Supplementary RATA information required under § 75.59(a)(7)(i) through § 75.59(a)(7)(v), except that:

(A) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (i.e., Method 2F or 2G in appendices A–1 and A–2 to part 60 of this chapter), with or without wall effects adjustments;

(B) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;

(C) The data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and

(D) The data under § 75.59(a)(7)(vii)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is applied.

* * * * *

§ 75.66 [Amended]

■ 31. Section 75.66 is amended by removing and reserving paragraph (f).

■ 32. Section 75.71 is amended by:

■ a. Revising the section heading;

■ b. In paragraph (a)(1), by removing the second occurrence of the phrase "CO_2 diluent gas monitor" and adding in its place the phrase "CO_2 diluent gas monitoring system";

■ c. Removing the phrase "O_2 or CO_2 diluent gas monitor" and adding in its place the phrase "O_2 or CO_2 monitoring system", in paragraph (a)(2); and

■ d. Revising paragraph (e).

The revision reads as follows:

§ 75.71 Specific provisions for monitoring NO_X and heat input for the purpose of calculating NO_X mass emissions.

* * * * *

(e) *Low mass emissions units.* Notwithstanding the requirements of paragraphs (c) and (d) of this section, for an affected unit using the low mass emissions (LME) unit under § 75.19 to estimate hourly NO_X emission rate, heat input and NO_X mass emissions, the owner or operator shall calculate the ozone season NO_X mass emissions by summing all of the estimated hourly NO_X mass emissions in the ozone season, as determined under § 75.19 (c)(4)(ii)(A), and dividing this sum by 2000 lb/ton.

* * * * *

■ 33. Section 75.72 is amended by:

■ a. Revising the section heading and the introductory text;

■ b. Revising paragraph (c)(3); and

■ c. Removing and reserving paragraph (f).

The revisions read as follows:

§ 75.72 Determination of NO_X mass emissions for common stack and multiple stack configurations.

The owner or operator of an affected unit shall either: calculate hourly NO_X mass emissions (in lbs) by multiplying the hourly NO_X emission rate (in lbs/

mmBtu) by the hourly heat input rate (in mmBtu/hr) and the unit or stack operating time (as defined in § 72.2), or, as provided in paragraph (e) of this section, calculate hourly NO_X mass emissions from the hourly NO_X concentration (in ppm) and the hourly stack flow rate (in scfh). Only one methodology for determining NO_X mass emissions shall be identified in the monitoring plan for each monitoring location at any given time. The owner or operator shall also calculate quarterly and cumulative year-to-date NO_X mass emissions and cumulative NO_X mass emissions for the ozone season (in tons) by summing the hourly NO_X mass emissions according to the procedures in section 8 of appendix F to this part.

* * * * *

(c) * * *

(3) Install, certify, operate, and maintain a NO_X-diluent CEMS and a flow monitoring system only on the main stack. If this option is chosen, it is not necessary to designate the exhaust configuration as a multiple stack configuration in the monitoring plan required under § 75.53, since only the main stack is monitored. For each unit operating hour in which the bypass stack is used and the emissions are either uncontrolled (or the add-on controls are not documented to be operating properly), report NO_X mass emissions as follows. If the unit heat input is determined using a flow monitor and a diluent monitor, report NO_X mass emissions using the maximum potential NO_X emission rate, the maximum potential flow rate, and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable). The maximum potential NO_X emission rate may be specific to the type of fuel combusted in the unit during the bypass (see § 75.33(c)(8)). If the unit heat input is determined using a fuel flowmeter, in accordance with appendix D to this part, report NO_X mass emissions as the product of the maximum potential NO_X emission rate and the actual measured hourly heat input rate. Alternatively, for a unit with NO_X add-on emission controls, for each unit operating hour in which the bypass stack is used but the add-on NO_X emission controls are not bypassed, the owner or operator may report the maximum controlled NO_X emission rate (MCR) instead of the maximum potential NO_X emission rate provided that the add-on controls are documented to be operating properly, as described in the quality assurance/quality control program for the unit, required by section 1 in appendix B of this part. To provide the necessary documentation, the owner or operator shall record parametric data to verify the proper operation of the NO_X add-on emission controls as described in § 75.34(d). Furthermore, the owner or operator shall calculate the MCR using the procedure described in section 2.1.2.1(b) of appendix A to this part by replacing the words "maximum potential NO_X emission rate (MER)" with the words "maximum controlled NO_X emission rate (MCR)" and by using the NO_X MEC in the calculations instead of the NO_X MPC.

* * * * *

(f) [Reserved]

* * * * *

■ 34. Section 75.73 is amended by:
■ a. Revising paragraph (c)(3);
■ b. Removing the number "45" and adding in its place the number "21" in paragraphs (e)(1) and (e)(2);
■ c. Revising paragraph (f)(1) introductory text;
■ d. Removing the phrase "paragraph (a)" and adding in its place the phrase "paragraphs (a) and (b)" in paragraph (f)(1)(ii) introductory text; and
■ e. Revising paragraph (f)(1)(ii)(K).

The revisions read as follows:

§ 75.73 Recordkeeping and reporting.

* * * * *

(c) * * *

(3) *Contents of the monitoring plan for units not subject to an Acid Rain emissions limitation.* Prior to January 1, 2009, each monitoring plan shall contain the information in § 75.53(e)(1) or § 75.53(g)(1) in electronic format and the information in § 75.53(e)(2) or § 75.53(g)(2) in hardcopy format. On and after January 1, 2009, each monitoring plan shall contain the information in § 75.53(g)(1) in electronic format and the information in § 75.53(g)(2) in hardcopy format, only. In addition, to the extent applicable, prior to January 1, 2009, each monitoring plan shall contain the information in § 75.53(f)(1)(i), (f)(2)(i), and (f)(4) or § 75.53(h)(1)(i), and (h)(2)(i) in electronic format and the information in § 75.53(f)(1)(ii) and (f)(2)(ii) or § 75.53(h)(1)(ii) and (h)(2)(ii) in hardcopy format. On and after January 1, 2009, each monitoring plan shall contain the information in § 75.53(h)(1)(i), and (h)(2)(i) in electronic format and the information in § 75.53(h)(1)(ii) and (h)(2)(ii) in hardcopy format, only. For units using the low mass emissions excepted methodology under § 75.19, prior to January 1, 2009, the monitoring plan shall include the additional information in § 75.53(f)(5)(i) and (f)(5)(ii) or § 75.53(h)(4)(i) and (h)(4)(ii). On and after January 1, 2009, for units using the low mass emissions excepted methodology under § 75.19 the monitoring plan shall include the additional information in § 75.53(h)(4)(i) and (h)(4)(ii), only. Prior to January 1, 2008, the monitoring plan shall also identify, in electronic format, the reporting schedule for the affected unit (ozone season or quarterly), and the beginning and end dates for the reporting schedule. The monitoring plan also shall include a seasonal controls indicator, and an ozone season fuel-switching flag.

* * * * *

(f) * * *

(1) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in this paragraph (f)(1) and in paragraphs (f)(2) and (3) of this section to the Administrator quarterly, unless the unit has been placed in long-term cold storage (as defined in § 72.2 of this chapter). For units placed into long-term cold storage during a reporting quarter, the exemption from submitting quarterly reports begins with the calendar quarter following the date that the unit is placed into long-term cold storage. In such cases, the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the unit recommences operation (where the initial quarterly report contains hourly data beginning with the first hour of recommenced operation of the unit). Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Except as otherwise provided in § 75.64(a)(4) and (a)(5), each electronic report shall include the information provided in paragraphs (f)(1)(i) through (1)(vi) of this section, and shall also include the date of report generation. Prior to January 1, 2009, each report shall include the facility information provided in paragraphs (f)(1)(i)(A) and (B) of this section, for each affected unit or group of units monitored at a common stack. On and after January 1, 2009, only the facility identification information provided in paragraph (f)(1)(i)(A) of this section is required.

* * * * *

(ii) * * *

(K) Supplementary RATA information required under § 75.59(a)(7), except that:

(*1*) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (i.e., Method

2F or 2G in appendices A–1 and A–2 to part 60 of this chapter), with or without wall effects adjustments;

(*2*) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;

(*3*) The data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and

(*4*) The data under § 75.59(a)(7)(ix)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is applied.

* * * * *

■ 35. Section 75.74 is amended by:

■ a. Removing the phrase "In the time period prior to the start of the current ozone season (i.e., in the period extending from October 1 of the previous calendar year through April 30 of the current calendar year), the", and adding in its place the word "The", in paragraph (c)(2) introductory text;

■ b. Adding the words "in the second calendar quarter no later than April 30" to the end of paragraph (c)(2)(i) introductory text;

■ c. Removing the phrase "of the current calendar year" from the first sentence, and removing the last sentence of paragraph (c)(2)(i)(C);

■ d. Revising paragraph (c)(2)(i)(D);

■ e. Adding the words "in the first or second calendar quarter, but no later than April 30" to the end of the first sentence, and by removing the second sentence of paragraph (c)(2)(ii) introductory text;

■ f. Removing the words "of the current calendar year" from paragraph (c)(2)(ii)(E);

■ g. Revising paragraph (c)(2)(ii)(F);

■ h. Removing paragraphs (c)(2)(ii)(G) and (c)(2)(ii)(H);

■ i. Revising paragraph (c)(3)(ii);

■ j. Removing and reserving paragraphs (c)(3)(vi) through (viii);

■ k. Removing all occurrences of the words "§ 75.31, § 75.33, or § 75.37" and adding in their place the words "§§ 75.31 through 75.37" in paragraphs (c)(3)(xi), (c)(3)(xii)(A), and (c)(3)(xii)(B);

■ l. Revising paragraph (c)(6)(iii);

■ m. Removing the words "October 1 of the previous calendar year" and adding in its place the words "January 1" in paragraph (c)(6)(v);

■ n. Revising paragraph (c)(7)(iii)(L);

■ o. Revising paragraph (c)(8)(ii); and

■ p. Revising paragraph (c)(11).

The revisions read as follows:

§ 75.74 Annual and ozone season monitoring and reporting requirements.

* * * * *

(c) * * *

(2) * * *

(i) * * *

(D) If the linearity check is not completed by April 30, data validation shall be determined in accordance with paragraph (c)(3)(ii)(E) of this section.

(ii) * * *

(F) *Data Validation.* For each RATA that is performed by April 30, data validation shall be done according to sections 2.3.2(a)–(j) of appendix B to this part. However, if a required RATA is not completed by April 30, data from the monitoring system shall be invalid, beginning with the first unit operating hour on or after May 1. The owner or operator shall continue to invalidate all data from the CEMS until either:

(*1*) The required RATA of the CEMS has been performed and passed; or

(*2*) A probationary calibration error test of the CEMS is passed in accordance with § 75.20(b)(3)(ii). Once the probationary calibration error test has been passed, the owner or operator shall perform the required RATA in accordance with the conditional data validation provisions and within the 720 unit or stack operating hour time frame specified in § 75.20(b)(3) (subject to the restrictions in paragraph (c)(3)(xii) of this section), and the term "quality assurance" shall apply instead of the term "recertification." However, in lieu of the provisions in § 75.20(b)(3)(ix), the owner or operator shall follow the applicable provisions in paragraphs (c)(3)(xi) and (c)(3)(xii) of this section.

(3) * * *

(ii) For each gas monitor required by this subpart, linearity checks shall be performed in the second and third calendar quarters, as follows:

(A) For the second calendar quarter, the pre-ozone season linearity check required under paragraph (c)(2)(i) of this section shall be performed by April 30.

(B) For the third calendar quarter, a linearity check shall be performed and passed no later than July 30.

(C) Conduct each linearity check in accordance with the general procedures in section 6.2 of appendix A to this part, except that the data validation procedures in sections 6.2(a) through (f) of appendix A do not apply.

(D) Each linearity check shall be done "hands-off," as described in section 2.2.3(c) of appendix B to this part.

(E) *Data Validation.* For second and third quarter linearity checks performed by the applicable deadline (i.e., April 30 or July 30), data validation shall be done in accordance with sections 2.2.3(a), (b), (c), (e), and (h) of Appendix B to this part. However, if a required linearity check for the second calendar quarter is not completed by April 30, or if a required linearity check for the third calendar quarter is not completed by July 30, data from the monitoring system (or range) shall be invalid, beginning with the first unit operating hour on or after May 1 or July 31, respectively. The owner or operator shall continue to invalidate all data from the CEMS until either:

(*1*) The required linearity check of the CEMS has been performed and passed; or

(*2*) A probationary calibration error test of the CEMS is passed in accordance with § 75.20(b)(3)(ii). Once the probationary calibration error test has been passed, the owner or operator shall perform the required linearity check in accordance with the conditional data validation provisions and within the 168 unit or stack operating hour time frame specified in § 75.20(b)(3) (subject to the restrictions in paragraph (c)(3)(xii) of this section), and the term "quality assurance" shall apply instead of the term "recertification." However, in lieu of the provisions in § 75.20(b)(3)(ix), the owner or operator shall follow the applicable provisions in paragraphs (c)(3)(xi) and (c)(3)(xii) of this section.

(F) A pre-season linearity check performed and passed in April satisfies the linearity check requirement for the second quarter.

(G) The third quarter linearity check requirement in paragraph (c)(3)(ii)(B) of this section is waived if:

(*1*) Due to infrequent unit operation, the 168 operating hour conditional data validation period associated with a pre-season linearity check extends into the third quarter; and

(*2*) A linearity check is performed and passed within that conditional data validation period.

* * * * *

(6) * * *

(iii) For the time periods described in paragraphs (c)(2)(i)(C) and (c)(2)(ii)(E) of this section, hourly emission data and the results of all daily calibration error tests and flow monitor interference checks shall be recorded. The owner or operator may opt to report unit operating data, daily calibration error test and flow monitor interference check results, and hourly emission data in the time period from April 1 through April

30. However, only the data recorded in the time period from May 1 through September 30 shall be used for NO_X mass compliance determination;

* * * * *

(7) * * *

(iii) * * *

(L) In § 75.34(a)(3) and (a)(5), the phrases "720 quality-assured monitor operating hours within the ozone season" and "2160 quality-assured monitor operating hours within the ozone season" apply instead of "720 quality-assured monitor operating hours" and "2160 quality-assured monitor operating hours", respectively.

(8) * * *

(ii) For units with add-on emission controls, using the missing data options in §§ 75.34(a)(1) through 75.34(a)(5), the range of operating parameters for add-on emission controls (as defined in the quality assurance/quality control program for the unit required by section 1 in appendix B to this part) and information for verifying proper operation of the add-on emission controls during missing data periods, as described in § 75.34(d).

* * * * *

(11) Units may qualify to use the optional NO_X mass emissions estimation protocol for gas-fired and oil-fired peaking units in appendix E to this part on an ozone season basis. In order to be allowed to use this methodology, the unit must meet the definition of "peaking unit" in § 72.2 of this chapter, except that the words "year", "calendar year" and "calendar years" in that definition shall be replaced by the words "ozone season", "ozone season", and "ozone seasons", respectively. In addition, in the definition of the term "capacity factor" in § 72.2 of this chapter, the word "annual" shall be replaced by the words "ozone season" and the number "8,760" shall be replaced by the number "3,672".

§ 75.80 [Amended]

■ 36. Section 75.80(f)(1)(iii) is amended by removing the words "or § 75.12(b),".

■ 37. Section 75.81 is amended by:

■ a. Removing the words "or § 75.12(b)" and "or § 75.12," from paragraph (a)(3);

■ b. Revising paragraph (a)(4);

■ c. Revising paragraph (c)(1);

■ d. Revising paragraph (c)(2);

■ e. Removing Eq. 1 from paragraph (d)(1);

■ f. Revising paragraph (d)(2);

■ g. Adding paragraph (d)(4)(iv); and

■ h. Revising paragraphs (d)(5) and (e)(1).

The revisions and additions read as follows:

§ 75.81 Monitoring of Hg mass emissions and heat input at the unit level.

* * * * *

(a) * * *

(4) If heat input is required to be reported under the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart, the owner or operator must meet the general operating requirements for a flow monitoring system and an O_2 or CO_2 monitoring system to measure heat input rate.

* * * * *

(c) * * *

(1) The owner or operator must perform Hg emission testing one year or less before the compliance date in § 75.80(b), to determine the Hg concentration (i.e., total vapor phase Hg) in the effluent.

(i) The testing shall be performed using one of the Hg reference methods listed in § 75.22(a)(7), and shall consist of a minimum of 3 runs at the normal unit operating load, while combusting coal. The coal combusted during the testing shall be representative of the coal that will be combusted at the start of the Hg mass emissions reduction program (preferably from the same source(s) of supply).

(ii) The minimum time per run shall be 1 hour if Method 30A is used. If either Method 29 in appendix A–8 to part 60 of this chapter, ASTM D6784–02 (the Ontario Hydro method) (incorporated by reference under § 75.6 of this part), or Method 30B is used, paired samples are required for each test run and the runs must be long enough to ensure that sufficient Hg is collected to analyze. When Method 29 in appendix A–8 to part 60 of this chapter or the Ontario Hydro method is used, the test results shall be based on the vapor phase Hg collected in the back-half of the sampling trains (i.e., the non-filterable impinger catches). For each Method 29 in appendix A–8 to part 60 of this chapter, Method 30B, or Ontario Hydro method test run, the paired trains must meet the relative deviation (RD) requirement specified in § 75.22(a)(7) or Method 30B, as applicable. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

(iii) If the unit is equipped with flue gas desulfurization or add-on Hg emission controls, the controls must be operating normally during the testing, and, for the purpose of establishing proper operation of the controls, the owner or operator shall record parametric data or SO_2 concentration data in accordance with § 75.58(b)(3)(i).

(iv) If two or more of units of the same type qualify as a group of identical units in accordance with § 75.19(c)(1)(iv)(B), the owner or operator may test a subset of these units in lieu of testing each unit individually. If this option is selected, the number of units required to be tested shall be determined from Table LM–4 in § 75.19. For the purposes of the required retests under paragraph (d)(4) of this section, EPA strongly recommends that (to the extent practicable) the same subset of the units not be tested in two successive retests, and that every effort be made to ensure that each unit in the group of identical units is tested in a timely manner.

(2)(i) Based on the results of the emission testing, Equation 1 of this section shall be used to provide a conservative estimate of the annual Hg mass emissions from the unit:

$$E = N\,K\,C_{Hg}\,Q_{max} \qquad \text{(Eq. 1)}$$

Where:

E = Estimated annual Hg mass emissions from the affected unit, (ounces/year)

K = Units conversion constant, 9.978×10^{-10} oz-scm/µg-scf

N = Either 8,760 (the number of hours in a year) or the maximum number of operating hours per year (if less than 8,760) allowed by the unit's Federally-enforceable operating permit.

C_{Hg} = The highest Hg concentration (µg/scm) from any of the test runs or 0.50 µg/scm, whichever is greater

Q_{max} = Maximum potential flow rate, determined according to section 2.1.4.1 of appendix A to this part, (scfh)

(ii) Equation 1 of this section assumes that the unit operates at its maximum potential flow rate, either year-round or for the maximum number of hours allowed by the operating permit (if unit operation is restricted to less than 8,760 hours per year). If the permit restricts the annual unit heat input but not the number of annual unit operating hours, the owner or operator may divide the allowable annual heat input (mmBtu) by the design rated heat input capacity of the unit (mmBtu/hr) to determine the value of "N" in Equation 1. Also, note that if the highest Hg concentration measured in any test run is less than 0.50 μg/scm, a default value of 0.50 μg/scm must be used in the calculations.

* * * * *

(d) * * *

(2) Following initial certification, the same default Hg concentration value that was used to estimate the unit's annual Hg mass emissions under paragraph (c) of this section shall be reported for each unit operating hour, except as otherwise provided in paragraph (d)(4)(iv) or (d)(6) of this section. The default Hg concentration value shall be updated as appropriate, according to paragraph (d)(5) of this section.

* * * * *

(4) * * *

(iv) An additional retest is required when there is a change in the coal rank of the primary fuel (e.g., when the primary fuel is switched from bituminous coal to lignite). Use ASTM D388–99 (incorporated by reference under § 75.6 of this part) to determine the coal rank. The four principal coal ranks are anthracitic, bituminous, subbituminous, and lignitic. The ranks of anthracite coal refuse (culm) and bituminous coal refuse (gob) shall be anthracitic and bituminous, respectively. The retest shall be performed within 720 unit operating hours of the change.

(5) The default Hg concentration used for reporting under § 75.84 shall be updated after each required retest. This includes retests that are required prior to the compliance date in § 75.80(b). The updated value shall either be the highest Hg concentration measured in any of the test runs or 0.50 μg/scm, whichever is greater. The updated value shall be applied beginning with the first unit operating hour in which Hg emissions data are required to be reported after completion of the retest, except as provided in paragraph (d)(4)(iv) of this section, where the need to retest is triggered by a change in the coal rank of the primary fuel. In that case, apply the updated default Hg concentration beginning with the first unit operating hour in which Hg emissions are required to be reported after the date and hour of the fuel switch.

* * * * *

(e) * * *

(1) The methodology may not be used for reporting Hg mass emissions at a common stack unless all of the units using the common stack are affected units and the units' combined potential to emit does not exceed 464 ounces of Hg per year times the number of units sharing the stack, in accordance with paragraphs (c) and (d) of this section. If the test results demonstrate that the units sharing the common stack qualify as low mass emitters, the default Hg concentration used for reporting Hg mass emissions at the common stack shall either be the highest value obtained in any test run or 0.50 μg/scm, whichever is greater.

(i) The initial emission testing required under paragraph (c) of this section may be performed at the common stack if the following conditions are met. Otherwise, testing of the individual units (or a subset of the units, if identical, as described in paragraph (c)(1)(iv) of this section) is required:

(A) The testing must be done at a combined load corresponding to the designated normal load level (low, mid, or high) for the units sharing the common stack, in accordance with section 6.5.2.1 of appendix A to this part;

(B) All of the units that share the stack must be operating in a normal, stable manner and at typical load levels during the emission testing. The coal combusted in each unit during the testing must be representative of the coal that will be combusted in that unit at the start of the Hg mass emission reduction program (preferably from the same source(s) of supply);

(C) If flue gas desulfurization and/or add-on Hg emission controls are used to reduce level the emissions exiting from the common stack, these emission controls must be operating normally during the emission testing and, for the purpose of establishing proper operation of the controls, the owner or operator shall record parametric data or SO_2 concentration data in accordance with § 75.58(b)(3)(i);

(D) When calculating E, the estimated maximum potential annual Hg mass emissions from the stack, substitute the maximum potential flow rate through the common stack (as defined in the monitoring plan) and the highest concentration from any test run (or 0.50 μg/scm, if greater) into Equation 1;

(E) The calculated value of E shall be divided by the number of units sharing the stack. If the result, when rounded to the nearest ounce, does not exceed 464 ounces, the units qualify to use the low mass emission methodology; and

(F) If the units qualify to use the methodology, the default Hg concentration used for reporting at the common stack shall be the highest value obtained in any test run or 0.50 μg/scm, whichever is greater; or

(ii) The retests required under paragraph (d)(4) of this section may also be done at the common stack. If this testing option is chosen, the testing shall be done at a combined load corresponding to the designated normal load level (low, mid, or high) for the units sharing the common stack, in accordance with section 6.5.2.1 of appendix A to this part. Provided that the required load level is attained and that all of the units sharing the stack are fed from the same on-site coal supply during normal operation, it is not necessary for all of the units sharing the stack to be in operation during a retest. However, if two or more of the units that share the stack are fed from different on-site coal supplies (e.g., one unit burns low-sulfur coal for compliance and the other combusts higher-sulfur coal), then either:

(A) Perform the retest with all units in normal operation; or

(B) If this is not possible, due to circumstances beyond the control of the owner or operator (e.g., a forced unit outage), perform the retest with the available units operating and assess the test results as follows. Use the Hg concentration obtained in the retest for reporting purposes under this part if the concentration is greater than or equal to the value obtained in the most recent test. If the retested value is lower than the Hg concentration from the previous test, continue using the higher value from the previous test for reporting purposes and use that same higher Hg concentration value in Equation 1 to determine the due date for the next retest, as described in paragraph (e)(1)(iii) of this section.

(iii) If testing is done at the common stack, the due date for the next scheduled retest shall be determined as follows:

(A) Substitute the maximum potential flow rate for the common stack (as defined in the monitoring plan) and the highest Hg concentration from any test run (or 0.50 μg/scm, if greater) into Equation 1;

(B) If the value of E obtained from Equation 1, rounded to the nearest ounce, is greater than 144 times the number of units sharing the common stack, but less than or equal to 464 times the number of units sharing the stack, the next retest is due in two QA operating quarters;

(C) If the value of E obtained from Equation 1, rounded to the nearest ounce, is less than or equal to 144 times the number of units sharing the common stack, the next retest is due in four QA operating quarters.

* * * * *

■ 38. Section 75.82 is amended by:

■ a. Adding paragraph (b)(3);

■ b. Removing the word "or" at the end of paragraph (c)(2);

■ c. Removing the period at the end of paragraph (c)(3), and adding in its place the phrase "; or";
■ d. Adding paragraph (c)(4);
■ e. Removing the word "or" at the end of paragraph (d)(1);
■ f. Removing the period at the end of paragraph (d)(2), and adding in its place the phrase "; or"; and
■ g. Adding paragraph (d)(3).

The revisions and additions read as follows:

§ 75.82 Monitoring of Hg mass emissions and heat input at common and multiple stacks.

* * * * *

(b) * * *

(3) If the monitoring option in paragraph (b)(2) of this section is selected, and if heat input is required to be reported under the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart, the owner or operator shall either:

(i) Apportion the common stack heat input rate to the individual units according to the procedures in § 75.16(e)(3); or

(ii) Install a flow monitoring system and a diluent gas (O_2 or CO_2) monitoring system in the duct leading from each affected unit to the common stack, and measure the heat input rate in each duct, according to section 5.2 of appendix F to this part.

(c) * * *

(4) If the monitoring option in paragraph (c)(1) or (c)(2) of this section is selected, and if heat input is required to be reported under the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart, the owner or operator shall:

(i) Use the installed flow and diluent monitors to determine the hourly heat input rate at each stack (mmBtu/hr), according to section 5.2 of appendix F to this part; and

(ii) Calculate the hourly heat input at each stack (in mmBtu) by multiplying the measured stack heat input rate by the corresponding stack operating time; and

(iii) Determine the hourly unit heat input by summing the hourly stack heat input values.

(d) * * *

(3) If the monitoring option in paragraph (d)(1) or (d)(2) of this section is selected, and if heat input is required to be reported under the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart, the owner or operator shall:

(i) Use the installed flow and diluent monitors to determine the hourly heat input rate at each stack or duct (mmBtu/hr), according to section 5.2 of appendix F to this part; and

(ii) Calculate the hourly heat input at each stack or duct (in mmBtu) by multiplying the measured stack (or duct) heat input rate by the corresponding stack (or duct) operating time; and

(iii) Determine the hourly unit heat input by summing the hourly stack (or duct) heat input values.

■ 39. Section 75.84 is amended by:
■ a. Removing "§ 75.53(e)(1)" and "§ 75.53(e)(2)" and adding in their place "§ 75.53(g)(1)" and "§ 75.53(g)(2)", in paragraph (c)(3);
■ b. Removing the number "45" and adding in its place the number "21" in paragraphs (e)(1) and (e)(2);
■ c. Revising paragraph (f)(1) introductory text;
■ d. Removing "§ 75.64(a)(1)" and adding in its place "§ 75.64(a)(3)" in paragraph (f)(1)(i);
■ e. Removing the phrase "paragraph (a)" and adding in its place the phrase "paragraphs (a) and (b)" in paragraph (f)(1)(ii) introductory text; and
■ f. Revising paragraph (f)(1)(ii)(I).

The revisions read as follows:

§ 75.84 Recordkeeping and reporting.

* * * * *

(f) * * *

(1) *Electronic submission.* Electronic quarterly reports shall be submitted, beginning with the calendar quarter containing the compliance date in § 75.80(b), unless otherwise specified in the final rule implementing a State or Federal Hg mass emissions reduction program that adopts the requirements of this subpart. The designated representative for an affected unit shall report the data and information in this paragraph (f)(1) and the applicable compliance certification information in paragraph (f)(2) of this section to the Administrator quarterly, except as otherwise provided in § 75.64(a) for units in long-term cold storage. Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Except as otherwise provided in § 75.64(a)(4) and (a)(5), each electronic report shall include the date of report generation and the following information for each affected unit or group of units monitored at a common stack:

* * * * *

(ii) * * *

(I) Supplementary RATA information required under § 75.59(a)(7), except that:

(*1*) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (i.e., Method 2F or 2G in appendices A–1 and A–2 to part 60 of this chapter), with or without wall effects adjustments;

(*2*) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;

(*3*) The data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and

(*4*) The data under § 75.59(a)(7)(ix)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is applied.

* * * * *

■ 40. Appendix A to Part 75 is amended by:
■ a. Revising paragraph (c) of section 2.1.1.1;
■ b. Revising paragraph (b)(2) of section 2.1.1.5;
■ c. Revising paragraph (b)(2) of section 2.1.2.5;
■ d. Adding a new fourth sentence after the third sentence of section 2.1.3;
■ e. Revising paragraph (3) of section 3.2;
■ f. Removing the phrase "continuous emission monitoring system(s)" and adding in its place the phrase "monitoring component of a continuous emission monitoring system that is" in section 3.5;
■ g. Adding the words "that meet the definition for a NIST Traceable Reference Material (NTRM) provided in § 72.2." after the word "gases" in section 5.1.3;
■ h. Revising sections 5.1.4 and 5.1.9;
■ i. Redesignating section 6.1 as section 6.1.1 and adding a new heading for 6.1;
■ j. Adding section 6.1.2;
■ k. Revising the second and third sentences and adding a new fourth sentence to section 6.2, introductory text;
■ l. Revising section 6.2(g);
■ m. Adding paragraph (h) to section 6.2;
■ n. Adding a new fourth sentence to section 6.3.1, introductory text;
■ o. Revising the introductory text of section 6.4;

■ p. Revising paragraph (e) in section 6.5;

■ q. Removing the words "that uses CEMS to account for its emissions and for each unit that uses the optional fuel flow-to-load quality assurance test in section 2.1.7 of appendix D to this part" from paragraph (a) of section 6.5.2.1;

■ r. Adding the words "or mmBtu/hr" after the words "klb/hr of steam production", and by adding the words "or mmBtu/hr of thermal output" after the words "thousands of lb/hr of steam load" in paragraph (a)(1) of section 6.5.2.1;

■ s. Adding the words "and units using the low mass emissions (LME) excepted methodology under § 75.19" after the words "(except for peaking units" in the second sentence in paragraph (c) of section 6.5.2.1;

■ t. Adding the words "and LME units" after the words "For peaking units" in the third sentence in paragraph (d)(1) of section 6.5.2.1;

■ u. Revising paragraph (e) of section 6.5.2.1;

■ v. Revising paragraph (c) in section 6.5.6;

■ w. Removing all occurrences of the words "section 3.2" and adding in its place the words "section 8.1.3" in paragraph (b)(3) of section 6.5.6, paragraph (a) of section 6.5.6.2, and paragraph (a) of section 6.5.6.3;

■ x. Revising section 6.5.10;

■ y. Adding two sentences at the end of section 7.6.1;

■ z. Revising the terms R_{ref} and L_{avg}, in paragraph (a) of section 7.7;

■ aa. Revising the terms $(GHR)_{ref}$ and L_{avg}, in paragraph (c) of section 7.7; and

■ bb. Removing Figure 6 and adding in its place Figures 6a and 6b and revising A through F and adding G at the end of appendix A.

The revisions and additions read as follows:

Appendix A to Part 75—Specifications and Procedures

* * * * *

2. Equipment Specifications

2.1.1.1 Maximum Potential Concentration

* * * * *

(c) When performing fuel sampling to determine the MPC, use ASTM Methods: ASTM D3177–02 (Reapproved 2007), Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke; ASTM D4239–02, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High-Temperature Tube Furnace Combustion Methods; ASTM D4294–98, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectrometry; ASTM D1552–01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method); ASTM D129–00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method); ASTM D2622–98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry, for sulfur content of solid or liquid fuels; ASTM D3176–89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke; ASTM D240–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter; or ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke (all incorporated by reference under § 75.6 of this part).

* * * * *

2.1.1.5 * * *

(b) * * *

(2) For units with two SO_2 spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and its most recent calibration error test and linearity check have not expired. However, if either of these quality assurance tests has expired and the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the SO_2 concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded follow the procedures in paragraph (b)(1) of this section).

* * * * *

2.1.2.5 * * *

(b) * * *

(2) For units with two NO_X spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and its most recent calibration error test and linearity check have not expired. However, if either of these quality assurance tests has expired and the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the NO_X concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded, follow the procedures in paragraph (b)(1) of this section).

* * * * *

2.1.3 CO_2 and O_2 Monitors

* * * An alternative CO_2 span value below 6.0 percent may be used if an appropriate technical justification is included in the hardcopy monitoring plan.

* * * * *

3.2 * * *

(3) For the linearity check and the 3-level system integrity check of an Hg monitor, which are required, respectively, under § 75.20(c)(1)(ii) and (c)(1)(vi), the measurement error shall not exceed 10.0 percent of the reference value at any of the three gas levels. To calculate the measurement error at each level, take the absolute value of the difference between the reference value and mean CEM response, divide the result by the reference value, and then multiply by 100. Alternatively, the results at any gas level are acceptable if the absolute value of the difference between the average monitor response and the average reference value, *i.e.*, $|R-A|$ in Equation A–4 of this appendix, does not exceed 0.8 µg/m³. The principal and alternative performance specifications in this section also apply to the single-level system integrity check described in section 2.6 of appendix B to this part.

* * * * *

5.1 *Reference Gases*

* * * * *

5.1.4 EPA Protocol Gases

(a) An EPA Protocol Gas is a calibration gas mixture prepared and analyzed according to Section 2 of the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA–600/R–97/121 or such revised procedure as approved by the Administrator (EPA Traceability Protocol).

(b) An EPA Protocol Gas must have a specialty gas producer-certified uncertainty (95-percent confidence interval) that must not be greater than 2.0 percent of the certified concentration (tag value) of the gas mixture. The uncertainty must be calculated using the statistical procedures (or equivalent statistical techniques) that are listed in Section 2.1.8 of the EPA Traceability Protocol.

(c) On and after January 1, 2009, a specialty gas producer advertising calibration gas certification with the EPA Traceability Protocol or distributing calibration gases as "EPA Protocol Gas" must participate in the EPA Protocol Gas Verification Program (PGVP) described in Section 2.1.10 of the EPA Traceability Protocol or it cannot use "EPA" in any form of advertising for these products, unless approved by the Administrator. A specialty gas producer not participating in the PGVP may not certify a calibration gas as an EPA Protocol Gas, unless approved by the Administrator.

(d) A copy of EPA–600/R–97/121 is available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA, 703–605–6585 or *http://www.ntis.gov*, and from *http://www.epa.gov/ttn/emc/news.html* or *http://www.epa.gov/appcdwww/tsb/index.html*.

* * * * *

5.1.9 Mercury Standards

For 7-day calibration error tests of Hg concentration monitors and for daily calibration error tests of Hg monitors, either NIST-traceable elemental Hg standards (as defined in § 72.2 of this chapter) or a NIST-traceable source of oxidized Hg (as defined in § 72.2 of this chapter) may be used. For linearity checks, NIST-traceable elemental Hg standards shall be used. For 3-level and single-point system integrity checks under § 75.20(c)(1)(vi), sections 6.2(g) and 6.3.1 of this appendix, and sections 2.1.1, 2.2.1 and 2.6 of appendix B to this part, a NIST-traceable source of oxidized Hg shall be used.

Alternatively, other NIST-traceable standards may be used for the required checks, subject to the approval of the Administrator. Notwithstanding these requirements, Hg calibration standards that are not NIST-traceable may be used for the tests described in this section until December 31, 2009. However, on and after January 1, 2010, only NIST-traceable calibration standards shall be used for these tests.

* * * * *

6.1 *General Requirements*

* * * * *

6.1.2 *Requirements for Air Emission Testing Bodies*

(a) On and after January 1, 2009, any Air Emission Testing Body (AETB) conducting relative accuracy test audits of CEMS and sorbent trap monitoring systems under this part must conform to the requirements of ASTM D7036–04 (incorporated by reference under § 75.6 of this part). This section is not applicable to daily operation, daily calibration error checks, daily flow interference checks, quarterly linearity checks or routine maintenance of CEMS.

(b) The AETB shall provide to the affected source(s) certification that the AETB operates in conformance with, and that data submitted to the Agency has been collected in accordance with, the requirements of ASTM D7036–04 (incorporated by reference under § 75.6 of this part). This certification may be provided in the form of:

(1) A certificate of accreditation of relevant scope issued by a recognized, national accreditation body; or

(2) A letter of certification signed by a member of the senior management staff of the AETB.

(c) The AETB shall either provide a Qualified Individual on-site to conduct or shall oversee all relative accuracy testing carried out by the AETB as required in ASTM D7036–04 (incorporated by reference under § 75.6 of this part). The Qualified Individual shall provide the affected source(s) with copies of the qualification credentials relevant to the scope of the testing conducted.

* * * * *

6.2 *Linearity Check (General Procedures)*

* * * Notwithstanding these requirements, if the SO_2 or NO_X span value for a particular monitor range is ≤ 30 ppm, that range is exempted from the linearity check requirements of this part, for initial certification, recertification, and for on-going quality-assurance. For units with two measurement ranges (high and low) for a particular parameter, perform a linearity check on both the low scale (except for SO_2 or NO_X span values ≤ 30 ppm) and the high scale. Note that for a NO_X-diluent monitoring system with two NO_X measurement ranges, if the low NO_X scale has a span value ≤ 30 ppm and is exempt from linearity checks, this does not exempt either the diluent monitor or the high NO_X scale (if the span is > 30 ppm) from linearity check requirements.

* * * * *

(g) For Hg monitors, follow the guidelines in section 2.2.3 of this appendix in addition to the applicable procedures in section 6.2 when performing the system integrity checks described in § 75.20(c)(1)(vi) and in sections 2.1.1, 2.2.1 and 2.6 of appendix B to this part.

(h) For Hg concentration monitors, if moisture is added to the calibration gas during the required linearity checks or system integrity checks, the moisture content of the calibration gas must be accounted for. Under these circumstances, the dry basis concentration of the calibration gas shall be used to calculate the linearity error or measurement error (as applicable).

* * * * *

6.3.1 *Gas Monitor 7-day Calibration Error Test*

* * * Also for Hg monitors, if moisture is added to the calibration gas, the added moisture must be accounted for and the dry-basis concentration of the calibration gas shall be used to calculate the calibration error.

* * * * *

6.4. *Cycle Time Test*

Perform cycle time tests for each pollutant concentration monitor and continuous emission monitoring system while the unit is operating, according to the following procedures. Use a zero-level and a high-level calibration gas (as defined in section 5.2 of this appendix) alternately. For Hg monitors, the calibration gas used for this test may either be the elemental or oxidized form of Hg. To determine the downscale cycle time, measure the concentration of the flue gas emissions until the response stabilizes. Record the stable emissions value. Inject a zero-level concentration calibration gas into the probe tip (or injection port leading to the calibration cell, for in situ systems with no probe). Record the time of the zero gas injection, using the data acquisition and handling system (DAHS). Next, allow the monitor to measure the concentration of the zero gas until the response stabilizes. Record the stable ending calibration gas reading. Determine the downscale cycle time as the time it takes for 95.0 percent of the step change to be achieved between the stable stack emissions value and the stable ending zero gas reading. Then repeat the procedure, starting with stable stack emissions and injecting the high-level gas, to determine the upscale cycle time, which is the time it takes for 95.0 percent of the step change to be achieved between the stable stack emissions value and the stable ending high-level gas reading. Use the following criteria to assess when a stable reading of stack emissions or calibration gas concentration has been attained. A stable value is equivalent to a reading with a change of less than 2.0 percent of the span value for 2 minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Alternatively, the reading is considered stable if it changes by no more than 0.5 ppm, 0.5 μg/m³ (for Hg), or 0.2% CO_2 or O_2 (as applicable) for two minutes. (Owners or operators of systems which do not record data in 1-minute or 3-minute intervals may petition the Administrator under § 75.66 for alternative stabilization criteria). For monitors or monitoring systems that perform a series of operations (such as purge, sample, and analyze), time the injections of the calibration gases so they will produce the longest possible cycle time. Refer to Figures 6a and 6b in this appendix for example calculations of upscale and downscale cycle times. Report the slower of the two cycle times (upscale or downscale) as the cycle time for the analyzer. Prior to January 1, 2009 for the NO_X-diluent continuous emission monitoring system test, either record and report the longer cycle time of the two component analyzers as the system cycle time or record the cycle time for each component analyzer separately (as applicable). On and after January 1, 2009, record the cycle time for each component analyzer separately. For time-shared systems, perform the cycle time tests at each probe locations that will be polled within the same 15-minute period during monitoring system operations. To determine the cycle time for time-shared systems, at each monitoring location, report the sum of the cycle time observed at that monitoring location plus the sum of the time required for all purge cycles (as determined by the continuous emission monitoring system manufacturer) at each of the probe locations of the time-shared systems. For monitors with dual ranges, report the test results for each range separately. Cycle time test results are acceptable for monitor or monitoring system certification, recertification or diagnostic testing if none of the cycle times exceed 15 minutes. The status of emissions data from a monitor prior to and during a cycle time test period shall be determined as follows:

* * * * *

6.5 * * *

(e) Complete each single-load relative accuracy test audit within a period of 168 consecutive unit operating hours, as defined in § 72.2 of this chapter (or, for CEMS installed on common stacks or bypass stacks, 168 consecutive stack operating hours, as defined in § 72.2 of this chapter). Notwithstanding this requirement, up to 336 consecutive unit or stack operating hours may be taken to complete the RATA of a Hg monitoring system, when ASTM 6784–02 (incorporated by reference under § 75.6 of this part) or Method 29 in appendix A–8 to part 60 of this chapter is used as the reference method. For 2-level and 3-level flow monitor RATAs, complete all of the RATAs at all levels, to the extent practicable, within a period of 168 consecutive unit (or stack) operating hours; however, if this is not possible, up to 720 consecutive unit (or stack) operating hours may be taken to complete a multiple-load flow RATA.

* * * * *

6.5.2.1 * * *

(e) The owner or operator shall report the upper and lower boundaries of the range of operation for each unit (or combination of units, for common stacks), in units of megawatts or thousands of lb/hr or mmBtu/hr of steam production or ft/sec (as applicable), in the electronic monitoring plan required under § 75.53. Except for peaking units and LME units, the owner or operator shall indicate, in the electronic monitoring plan, the load level (or levels) designated as normal under this section and shall also indicate the two most frequently used load levels.

* * * * *

6.5.6 * * *

(c) For Hg monitoring systems, use the same basic approach for traverse point selection that is used for the other gas monitoring system RATAs, except that the stratification test provisions in sections 8.1.3 through 8.1.3.5 of Method 30A shall apply, rather than the provisions of sections 6.5.6.1 through 6.5.6.3 of this appendix.

6.5.10 *Reference Methods*

The following methods are from appendix A to part 60 of this chapter or have been published by ASTM, and are the reference methods for performing relative accuracy test audits under this part: Method 1 or 1A in appendix A–1 to part 60 of this chapter for siting; Method 2 in appendices A–1 and A–2 to part 60 of this chapter or its allowable alternatives in appendix A to part 60 of this chapter (except for Methods 2B and 2E in appendix A–1 to part 60 of this chapter) for stack gas velocity and volumetric flow rate; Methods 3, 3A or 3B in appendix A–2 to part 60 of this chapter for O_2 and CO_2; Method 4 in appendix A–3 to part 60 of this chapter for moisture; Methods 6, 6A or 6C in appendix A–4 to part 60 of this chapter for SO_2; Methods 7, 7A, 7C, 7D or 7E in appendix A–4 to part 60 of this chapter for NO_X, excluding the exceptions of Method 7E in appendix A–4 to part 60 of this chapter identified in § 75.22(a)(5); and for Hg, either ASTM D6784–02 (the Ontario Hydro Method) (incorporated by reference under § 75.6 of this part), Method 29 in appendix A–8 to part 60 of this chapter, Method 30A, or Method 30B When using Method 7E in appendix A–4 to part 60 of this chapter for measuring NO_X concentration, total NO_X, both NO and NO_2, must be measured.

* * * * *

7.6 *Bias Test and Adjustment Factor*

* * * * *

7.6.1 * * * To calculate bias for a Hg monitoring system when using the Ontario Hydro Method or Method 29 in appendix A–8 to part 60 of this chapter, "d" is, for each data point, the difference between the average Hg concentration value (in $\mu g/m^3$) from the paired Ontario Hydro or Method 29 in appendix A–8 to part 60 of this chapter sampling trains and the concentration measured by the monitoring system. For sorbent trap monitoring systems, use the average Hg concentration measured by the paired traps in the calculation of "d".

* * * * *

7.7 * * *

(a) * * *

R_{ref} = Reference value of the flow-to-load ratio, from the most recent normal-load flow RATA, scfh/megawatts, scfh/1000 lb/hr of steam, or scfh/(mmBtu/hr of steam output).

* * * * *

L_{avg} = Average unit load during the normal-load flow RATA, megawatts, 1000 lb/hr of steam, or mmBtu/hr of thermal output.

* * * * *

(c) * * *

$(GHR)_{ref}$ = Reference value of the gross heat rate at the time of the most recent normal-load flow RATA, Btu/kwh, Btu/lb steam load, or Btu heat input/mmBtu steam output.

* * * * *

L_{avg} = Average unit load during the normal-load flow RATA, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

Figure 6a. Upscale Cycle Time Test

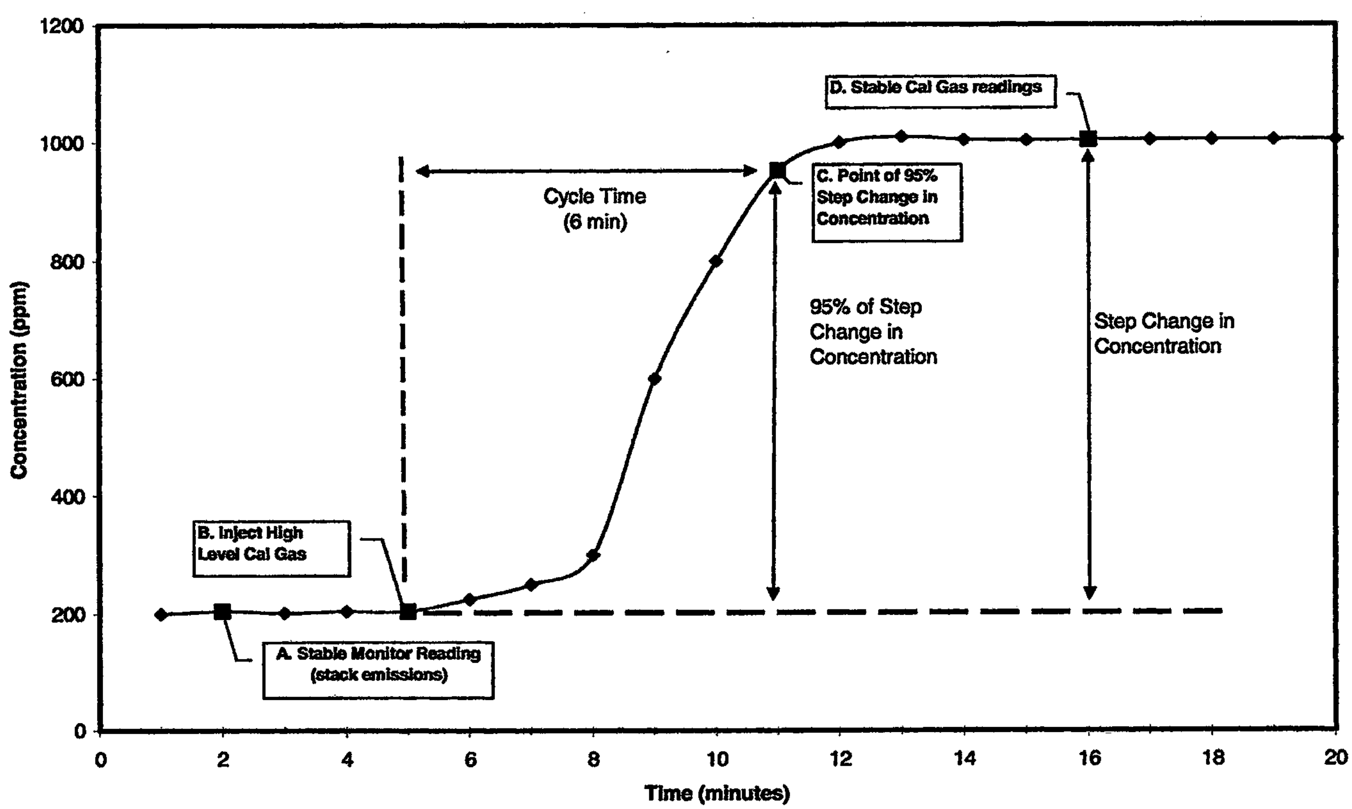
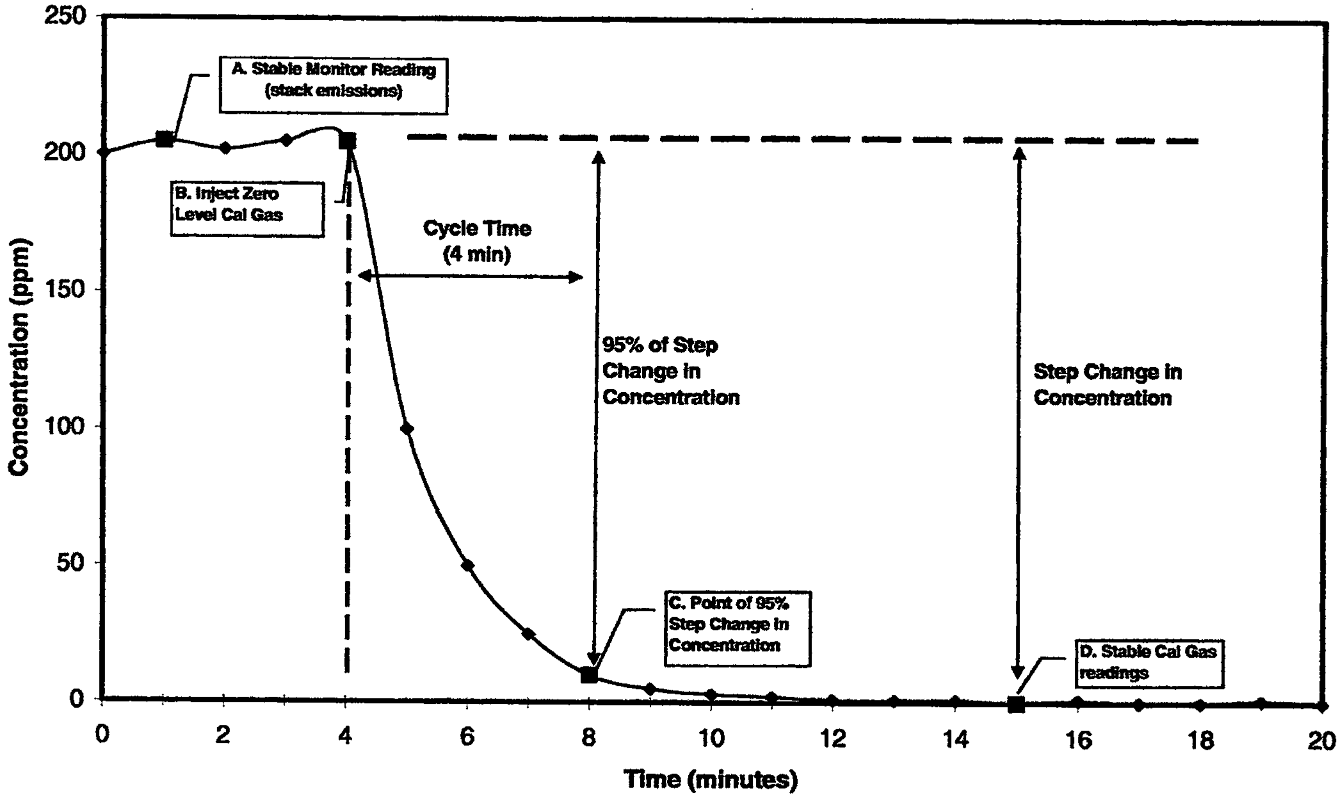


Figure 6b. Downscale Cycle Time Test



A. To determine the upscale cycle time (Figure 6a), measure the flue gas emissions until the response stabilizes. Record the stabilized value (see section 6.4 of this appendix for the stability criteria).

B. Inject a high-level calibration gas into the port leading to the calibration cell or thimble (Point B). Allow the analyzer to stabilize. Record the stabilized value.

C. Determine the step change. The step change is equal to the difference between the final stable calibration gas value (Point D) and the stabilized stack emissions value (Point A).

D. Take 95% of the step change value and add the result to the stabilized stack emissions value (Point A). Determine the time at which 95% of the step change occurred (Point C).

E. Calculate the upscale cycle time by subtracting the time at which the calibration gas was injected (Point B) from the time at which 95% of the step change occurred (Point C). In this example, upscale cycle time = (11 − 5) = 6 minutes.

F. To determine the downscale cycle time (Figure 6b) repeat the procedures above, except that a zero gas is injected when the flue gas emissions have stabilized, and 95% of the step change in concentration is subtracted from the stabilized stack emissions value.

G. Compare the upscale and downscale cycle time values. The longer of these two times is the cycle time for the analyzer.

■ 41. Appendix B to Part 75 is amended by:

■ a. Adding section 1.1.4;

■ b. Revising section 2.1.1;

■ c. Revising paragraph (2) of section 2.1.1.2;

■ d. Revising paragraph (2) of section 2.1.5.1;

■ e. Adding paragraph (3) to section 2.1.5.1;

■ f. Adding a new fourth sentence to paragraph (e) of section 2.2.3;

■ g. Revising the terms "R_h" and "L_h" in paragraph (a) of section 2.2.5;

■ h. Revising the terms "$(GHR)_h$" and "L_h" in paragraph (a)(2) of section 2.2.5;

■ i. Removing the word "five" and adding in its place the word "twenty", and by removing the word "years" and adding in its place the word "quarters", in paragraph (c)(4) of section 2.3.1.3;

■ j. Revising paragraphs (d) and (g) of section 2.3.2;

■ k. Revising paragraphs (a)(2) and (c) of section 2.3.3;

■ l. Adding paragraph (d) to section 2.3.3;

■ m. Revising section 2.6;

■ n. Revising Figure 1; and

■ o. Revising Figure 2.

The revisions and additions read as follows:

Appendix B to Part 75—Quality Assurance and Quality Control Procedures

1. Quality Assurance/Quality Control Program

* * * * *

1.1.4 The requirements in section 6.1.2 of appendix A to this part shall be met by any Air Emissions Testing Body (AETB) performing the semiannual/annual RATAs described in section 2.3 of this appendix and the Hg emission tests described in §§ 75.81(c) and 75.81(d)(4).

* * * * *

2. Frequency of Testing

* * * * *

2.1.1 Calibration Error Test

Except as provided in section 2.1.1.2 of this appendix, perform the daily calibration error test of each gas monitoring system (including moisture monitoring systems consisting of wet- and dry-basis O_2 analyzers) according to the procedures in section 6.3.1 of appendix A to this part, and perform the daily calibration error test of each flow monitoring system according to the procedure in section 6.3.2 of appendix A to this part. When two measurement ranges (low and high) are required for a particular parameter, perform sufficient calibration error tests on each range to validate the data recorded on that range, according to the criteria in section 2.1.5 of this appendix.

* * * * *

2.1.1.2 * * *

(2) For each monitoring system that has passed the off-line calibration demonstration, off-line calibration error tests may be used on a limited basis to validate data, in accordance with paragraph (2) in section 2.1.5.1 of this appendix.

* * * * *

2.1.5.1 * * *

(2) For a monitor that has passed the off-line calibration demonstration, a combination of on-line and off-line calibration error tests may be used to validate data from the monitor, as follows. For a particular unit (or stack) operating hour, data from a monitor may be validated using a successful off-line calibration error test if: (a) An on-line calibration error test has been passed within the previous 26 unit (or stack) operating hours; and (b) the 26 clock hour data validation window for the off-line calibration error test has not expired. If either of these conditions is not met, then the data from the monitor are invalid with respect to the daily calibration error test requirement. Data from the monitor shall remain invalid until the appropriate on-line or off-line calibration error test is successfully completed so that both conditions (a) and (b) are met.

(3) For units with two measurement ranges (low and high) for a particular parameter, when separate analyzers are used for the low and high ranges, a failed or expired calibration on one of the ranges does not affect the quality-assured data status on the other range. For a dual-range analyzer (i.e., a single analyzer with two measurement scales), a failed calibration error test on either the low or high scale results in an out-of-control period for the monitor. Data from the monitor remain invalid until corrective actions are taken and "hands-off" calibration error tests have been passed on both ranges. However, if the most recent calibration error test on the high scale was passed but has expired, while the low scale is up-to-date on its calibration error test requirements (or vice-versa), the expired calibration error test does not affect the quality-assured status of the data recorded on the other scale.

* * * * *

2.2.3 * * *

(e) * * * For a dual-range analyzer, "hands-off" linearity checks must be passed on both measurement scales to end the out-of-control period. * * *

* * * * *

2.2.5 * * *

(a) * * *

R_h = Hourly value of the flow-to-load ratio, scfh/megawatts, scfh/1000 lb/hr of steam, or scfh/(mmBtu/hr thermal output).

* * * * *

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output; must be within + 10.0 percent of L_{avg} during the most recent normal-load flow RATA.

* * * * *

(2) * * *

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh, Btu/lb steam load, or 1000 mmBtu heat input/mmBtu thermal output.

* * * * *

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output; must be within + 10.0 percent of L_{avg} during the most recent normal-load flow RATA.

* * * * *

2.3.2 * * *

(d) For single-load (or single-level) RATAs, if a daily calibration error test is failed during a RATA test period, prior to completing the test, the RATA must be repeated. Data from the monitor are invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test. The subsequent RATA shall not be commenced until the monitor has successfully passed a calibration error test in accordance with section 2.1.3 of this appendix. Notwithstanding these requirements, when ASTM D6784–02 (incorporated by reference under § 75.6 of this part) or Method 29 in appendix A–8 to part 60 of this chapter is used as the reference method for the RATA of a Hg CEMS, if a calibration error test of the CEMS is failed during a RATA test period, any test run(s) completed prior to the failed calibration error test need not be repeated; however, the RATA may not continue until a subsequent calibration error test of the Hg CEMS has been passed. For multiple-load (or multiple-level) flow RATAs, each load level (or operating level) is treated as a separate RATA (*i.e.*, when a calibration error test is failed prior to completing the RATA at a particular load level (or operating level), only the RATA at that load level (or operating level) must be repeated; the results of any previously-passed RATA(s) at the other load level(s) (or operating level(s)) are unaffected, unless re-linearization of the monitor is required to correct the problem that caused the calibration failure, in which case a subsequent 3-load (or 3-level) RATA is required), except as otherwise provided in section 2.3.1.3(c)(5) of this appendix.

* * * * *

(g) Data validation for failed RATAs for a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions), a NO_X pollutant concentration monitor, and a NO_X-diluent monitoring system shall be done according to paragraphs (g)(1) and (g)(2) of this section:

(1) For a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions) which also serves as the diluent component in a NO_X-diluent monitoring system, if the CO_2 (or O_2) RATA is failed, then both the CO_2 (or O_2) monitor and the associated NO_X-diluent system are considered out-of-control, beginning with the hour of completion of the failed CO_2 (or O_2) monitor RATA, and continuing until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.3 of appendix A to this part, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in § 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B).

(2) This paragraph (g)(2) applies only to a NO_X pollutant concentration monitor that serves both as the NO_X component of a NO_X concentration monitoring system (to measure NO_X mass emissions) and as the NO_X component in a NO_X-diluent monitoring system (to measure NO_X emission rate in lb/mmBtu). If the RATA of the NO_X concentration monitoring system is failed, then both the NO_X concentration monitoring system and the associated NO_X-diluent monitoring system are considered out-of-control, beginning with the hour of completion of the failed NO_X concentration RATA, and continuing until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.7 of appendix A to this part, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in § 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B).

* * * * *

2.3.3 RATA Grace Period

(a) * * *

(2) A required 3-load flow RATA has not been performed by the end of the calendar quarter in which it is due; or

* * * * *

(c) If, at the end of the 720 unit (or stack) operating hour grace period, the RATA has not been completed, data from the monitoring system shall be invalid, beginning with the first unit operating hour following the expiration of the grace period. Data from the CEMS remain invalid until the hour of completion of a subsequent hands-off RATA. The deadline for the next test shall be either two QA operating quarters (if a semiannual RATA frequency is obtained) or four QA operating quarters (if an annual RATA frequency is obtained) after the quarter in which the RATA is completed, not to exceed eight calendar quarters.

* * * * *

(d) When a RATA is done during a grace period in order to satisfy a RATA requirement from a previous quarter, the deadline for the next RATA shall determined as follows:

(1) If the grace period RATA qualifies for a reduced, (i.e., annual), RATA frequency the deadline for the next RATA shall be set at three QA operating quarters after the quarter in which the grace period test is completed.

(2) If the grace period RATA qualifies for the standard, (i.e., semiannual), RATA frequency the deadline for the next RATA shall be set at two QA operating quarters after the quarter in which the grace period test is completed.

(3) Notwithstanding these requirements, no more than eight successive calendar quarters shall elapse after the quarter in which the grace period test is completed, without a subsequent RATA having been conducted.

* * * * *

2.6 *System Integrity Checks for Hg Monitors*

For each Hg concentration monitoring system (except for a Hg monitor that does not have a converter), perform a single-point system integrity check weekly, i.e., at least once every 168 unit or stack operating hours, using a NIST-traceable source of oxidized Hg. Perform this check using a mid- or high-level gas concentration, as defined in section 5.2 of appendix A to this part. The performance specifications in paragraph (3) of section 3.2 of appendix A to this part must be met, otherwise the monitoring system is considered out-of-control, from the hour of the failed check until a subsequent system integrity check is passed. If a required system integrity check is not performed and passed within 168 unit or stack operating hours of last successful check, the monitoring system shall also be considered out of control, beginning with the 169th unit or stack operating hour after the last successful check, and continuing until a subsequent system integrity check is passed. This weekly check is not required if the daily calibration assessments in section 2.1.1 of this appendix are performed using a NIST-traceable source of oxidized Hg.

* * * * *

FIGURE 1 TO APPENDIX B OF PART 75.—QUALITY ASSURANCE TEST REQUIREMENTS

Test	Basic QA test frequency requirements*				
	Daily*	Weekly	Quarterly*	Semi-annual*	Annual
Calibration Error Test (2 pt.)	✔				
Interference Check (flow)	✔				
Flow-to-Load Ratio			✔		
Leak Check (DP flow monitors)			✔		
Linearity Check or System Integrity Check** (3 pt.)			✔		
Single-point System Integrity Check**		✔			
RATA (SO_2, NO_X, CO_2, O_2, H_2O)[1]				✔	
RATA (All Hg monitoring systems)					✔
RATA (flow)[1 2]				✔	

* "Daily" means operating days, only. "Weekly" means once every 168 unit or stack operating hours. "Quarterly" means once every QA operating quarter. "Semiannual" means once every two QA operating quarters. "Annual" means once every four QA operating quarters.

** The system integrity check applies only to Hg monitors with converters. The single-point weekly system integrity check is not required if daily calibrations are performed using a NIST-traceable source of oxidized Hg. The 3-point quarterly system integrity check is not required if a linearity check is performed.

[1] Conduct RATA annually (i.e., once every four QA operating quarters), if monitor meets accuracy requirements to qualify for less frequent testing.

[2] For flow monitors installed on peaking units, bypass stacks, or units that qualify for single-level RATA testing under section 6.5.2(e) of this part, conduct all RATAs at a single, normal load (or operating level). For other flow monitors, conduct annual RATAs at two load levels (or operating levels). Alternating single-load and 2-load (or single-level and 2-level) RATAs may be done if a monitor is on a semiannual frequency. A single-load (or single-level) RATA may be done in lieu of a 2-load (or 2-level) RATA if, since the last annual flow RATA, the unit has operated at one load level (or operating level) for ≥85.0 percent of the time. A 3-level RATA is required at least once every five calendar years and whenever a flow monitor is re-linearized, except for flow monitors exempted from 3-level RATA testing under section 6.5.2(b) or 6.5.2(e) of appendix A to this part.

FIGURE 2 TO APPENDIX B OF PART 75.—RELATIVE ACCURACY TEST FREQUENCY INCENTIVE SYSTEM

RATA	Semiannual[W] (percent)	Annual[W]
SO_2 or NO_X[Y]	7.5% <RA ≤10.0% or ±15.0 ppm[X]	RA ≤ 7.5% or ±12.0 ppm[X].
SO_2-diluent	7.5% <RA ≤10.0% or ±0.030 lb/mmBtu[X]	RA ≤7.5% or ±0.025 lb/mmBtu=G5X.
NO_X-diluent	7.5% <RA ≤10.0% or ±0.020 lb/mmBtu[X]	RA ≤ 7.5% or ±0. 015 lb/mmBtu[X].
Flow	7.5% < RA ≤ 10.0% or ±2.0 fps[X]	RA ≤ 7.5% or ±1.5 fps[X].
CO_2 or O_2	7.5% < RA ≤ 10.0% or ±1.0% CO_2/O_2[X]	RA ≤ 7.5% or ±0.7% CO_2/O_2[X].
Hg[X]	N/A	RA < 20.0% or ± 1.0 µg/scm[X].
Moisture	7.5% <RA ≤10.0% or ±1.5% H_2O[X]	RA ≤7.5% or ±1.0% H_2O[X].

[W] The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarter following the quarter in which the CEMS was last tested. Exclude calendar quarters with fewer than 168 unit operating hours (or, for common stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in determining the RATA deadline. For SO_2 monitors, QA operating quarters in which only very low sulfur fuel as defined in § 72.2, is combusted may also be excluded. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more than 8 calendar quarters after the quarter in which a RATA was last performed.

[X] The difference between monitor and reference method mean values applies to moisture monitors, CO_2, and O_2 monitors, low emitters of SO_2, NO_X, or Hg, or and low flow, only. The specifications for Hg monitors also apply to sorbent trap monitoring systems.

[Y] A NO_X concentration monitoring system used to determine NO_X mass emissions under § 75.71.

■ 42. Appendix D to Part 75 is amended by:

■ a. Revising section 2.1.5.1;

■ b. Removing all "±" symbols from paragraph (c) of section 2.1.6.1;

■ c. Revising the R_{base} and L_{avg} variable definitions in paragraph (a) of section 2.1.7.1;

■ d. Revising the terms "$(GHR)_{base}$" and "L_{avg}" in paragraph (c) of section 2.1.7.1;

■ e. Revising the terms "R_h" and "L_h" in paragraph (a) of section 2.1.7.2;

■ f. Revising the terms "$(GHR)_h$" and "L_h" in paragraph (c) of section 2.1.7.2;

■ g. Removing "D4177–82 (Reapproved 1990)" and adding in its place "D4177–95 (Reapproved 2000)", in the first sentence of section 2.2.3;

■ h. Removing "D4057–88 'Standard Practice for Manual Sampling of Petroleum and Petroleum Products' (incorporated by reference under § 75.6)" and adding in its place, "ASTM D4057–95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products (incorporated by reference under § 75.6 of this part)", in sections 2.2.4.1 and 2.2.4.2, and in paragraph (c) of section 2.2.4.3;

■ i. Revising sections 2.2.5, 2.2.6, and 2.2.7;

■ j. Revising paragraphs (a)(2) and (e) of section 2.3.1.4;

■ k. Revising section 2.3.3.1.2;

■ l. Revising section 2.3.4;

■ m. Adding two sentences at the end of section 2.3.4.1;

■ n. Revising paragraphs (b)(2) and (c) of section 2.3.7;

■ o. Revising section 3.2.2; and

■ p. Revising section 3.5.1.

The revisions and additions read as follows:

Appendix D to Part 75—Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units.

* * * * *

2. Procedure

* * * * *

2.1.5.1 Use the procedures in the following standards to verify flowmeter accuracy or design, as appropriate to the type of flowmeter: ASME MFC–3M–2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi; ASME MFC–4M–1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters; American Gas Association Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines (October 1990 Edition), Part 2: Specification and Installation Requirements (February 1991 Edition), and Part 3: Natural Gas Applications (August 1992 edition) (excluding the modified flow-calculation method in part 3); Section 8, Calibration from American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Second Revision, April 1996); ASME–MFC–5M–1985, (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters; ASME MFC–6M–1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters; ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles; ISO 8316: 1987(E) Measurement of Liquid Flow in Closed Conduits-Method by Collection of the Liquid in a Volumetric Tank; American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4—Proving Systems, Section 2—Pipe Provers (Provers Accumulating at Least 10,000 Pulses), Second Edition, March 2001, and Section 5—Master-Meter Provers, Second Edition, May 2000; American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices, First Edition, August 2005; or ASME MFC–9M–1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method, for all other flowmeter types (all incorporated by reference under § 75.6 of this part). The Administrator may also approve other procedures that use equipment traceable to National Institute of Standards and Technology standards. Document such procedures, the equipment used, and the accuracy of the procedures in the monitoring plan for the unit, and submit a petition signed by the designated representative under § 75.66(c). If the flowmeter accuracy exceeds 2.0 percent of the upper range value, the flowmeter does not qualify for use under this part.

* * * * *

2.1.7.1

(a) * * *

Where:

R_{base} = Value of the fuel flow rate-to-load ratio during the baseline period; 100 scfh/MWe, 100 scfh/klb per hour steam load, or 100 scfh/mmBtu per hour thermal output for gas-firing; (lb/hr)/MWe, (lb/hr)/klb per hour steam load, or (lb/hr)/mmBtu per hour thermal output for oil-firing.

* * * * *

L_{avg} = Arithmetic average unit load during the baseline period, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

* * * * *

(c) * * *

Where:

$(GHR)_{base}$ = Baseline value of the gross heat rate during the baseline period, Btu/kwh, Btu/lb steam load, or 1000mmBtu heat input/mmBtu thermal output.

* * * * *

L_{avg} = Average (mean) unit load during the baseline period, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

* * * * *

2.1.7.2

(a) * * *

Where:

R_h = Hourly value of the fuel flow rate-to-load ratio; 100 scfh/MWe, (lb/hr)/MWe, 100 scfh/1000 lb/hr of steam load, (lb/hr)/1000 lb/hr of steam load, 100 scfh/(mmBtu/hr of steam load), or (lb/hr)/(mmBtu/hr thermal output).

* * * * *

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

* * * * *

(c) * * *

Where:

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh, Btu/lb steam load, or mmBtu heat input/mmBtu thermal output.

* * * * *

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

* * * * *

2.2.5 For each oil sample that is taken on-site at the affected facility, split and label the sample and maintain a portion (at least 200 cc) of it throughout the calendar year and in all cases for not less than 90 calendar days after the end of the calendar year allowance accounting period. This requirement does not apply to oil samples taken from the fuel supplier's storage container, as described in section 2.2.4.3 of this appendix. Analyze oil samples for percent sulfur content by weight in accordance with ASTM D129–00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), ASTM D1552–01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), ASTM D2622–98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry, ASTM D4294–98, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectrometry, or ASTM D5453–06, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence (all incorporated by reference under § 75.6 of this part). Alternatively, the oil samples may be analyzed for percent sulfur by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.2.6 Where the flowmeter records volumetric flow rate rather than mass flow rate, analyze oil samples to determine the density or specific gravity of the oil. Determine the density or specific gravity of the oil sample in accordance with ASTM D287–92 (Reapproved 2000), Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), ASTM D1217–93 (Reapproved 1998), Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer, ASTM D1481–93 (Reapproved 1997), Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary Pycnometer, ASTM D1480–93 (Reapproved 1997), Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer, ASTM D1298–99, Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, or ASTM D4052–96 (Reapproved 2002), Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter (all incorporated by reference under § 75.6 of this part). Alternatively, the oil samples may be analyzed for density or specific gravity by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.2.7 Analyze oil samples to determine the heat content of the fuel. Determine oil heat content in accordance with ASTM D240–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, ASTM D4809–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), or ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke (all incorporated by reference under § 75.6 of this part) or any other procedures listed in section 5.5 of appendix F of this part. Alternatively, the oil samples may be analyzed for heat content by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

* * * * *

2.3.1.4 * * *

(a) * * *

(2) Historical fuel sampling data for the previous 12 months, documenting the total sulfur content of the fuel and the GCV and/or percentage by volume of methane. The results of all sample analyses obtained by or provided to the owner or operator in the previous 12 months shall be used in the demonstration, and each sample result must meet the definition of pipeline natural gas in § 72.2 of this chapter, except where the results of at least 100 daily (or more frequent) total sulfur samples are provided by the fuel supplier. In that case you may opt to convert these data to monthly averages and then if, for each month, the average total sulfur content is 0.5 grains/100 scf or less, and if the GCV or percent methane requirement is also met, the fuel qualifies as pipeline natural gas. Alternatively, the fuel qualifies as pipeline natural gas if ≥ 98 percent of the 100 (or more) samples have a total sulfur content of 0.5 grains/100 scf or less and if the GCV or percent methane requirement is also met; or

* * * * *

(e) If a fuel qualifies as pipeline natural gas based on the specifications in a fuel contract or tariff sheet, no additional, on-going sampling of the fuel's total sulfur content is required, provided that the contract or tariff sheet is current, valid and representative of the fuel combusted in the unit. If the fuel qualifies as pipeline natural gas based on fuel sampling and analysis, on-going sampling of the fuel's sulfur content is required annually and whenever the fuel supply source changes. For the purposes of this paragraph (e), sampling "annually" means that at least one sample is taken in each calendar year. If the results of at least 100 daily (or more frequent) total sulfur samples have been provided by the fuel supplier since the last annual assessment of the fuel's sulfur content, the data may be used as follows to satisfy the annual sampling requirement for the current year. If this option is chosen, all of the data provided by the fuel supplier shall be used. First, convert the data to monthly averages. Then, if, for each month, the average total sulfur content is 0.5 grains/100 scf or less, and if the GCV or percent methane requirement is also met, the fuel qualifies as pipeline natural gas. Alternatively, the fuel qualifies as pipeline natural gas if the analysis of the 100 (or more) total sulfur samples since the last annual assessment shows that ≥ 98 percent of the samples have a total sulfur content of 0.5 grains/100 scf or less and if the GCV or percent methane requirement is also met. The effective date of the annual total sulfur sampling requirement is January 1, 2003.

* * * * *

2.3.3.1.2 Use one of the following methods when using manual sampling (as applicable to the type of gas combusted) to determine the sulfur content of the fuel: ASTM D1072–06, Standard Test Method for Total Sulfur in Fuel Gases by Combustion and Barium Chloride Titration, ASTM D4468–85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, ASTM D5504–01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, or ASTM D3246–96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, (all incorporated by reference under § 75.6 of this part). Alternatively, the gas samples may be analyzed for percent sulfur by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

* * * * *

2.3.4 Gross Calorific Values for Gaseous Fuels

Determine the GCV of each gaseous fuel at the frequency specified in this section, using one of the following methods: ASTM D1826–94 (Reapproved 1998), ASTM D3588–98, ASTM D4891–89 (Reapproved 2006), GPA Standard 2172–96, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, or GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (all incorporated by reference under § 75.6 of this part). Use the appropriate GCV value, as specified in section 2.3.4.1, 2.3.4.2, or 2.3.4.3 of this appendix, in the calculation of unit hourly heat input rates. Alternatively, the gas samples may be analyzed for heat content by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.3.4.1 GCV of Pipeline Natural Gas

* * * If multiple GCV samples are taken and analyzed in a particular month, the GCV values from all samples shall be averaged arithmetically to obtain the monthly GCV. Then, apply the monthly average GCV value as described in paragraph (c) in section 2.3.7 of this appendix.

* * * * *

2.3.7 * * *

(b) * * *

(2) For natural gas, if only one sample is taken, apply the results beginning at the date on which the sample was taken. If multiple samples are taken and averaged, apply the results beginning at the date on which the last sample used in the annual assessment was taken;

* * * * *

(c) For monthly samples of the fuel GCV:

(1) If the actual monthly value is to be used in the calculations and only one sample is taken, apply the results starting from the date on which the sample was taken. If multiple samples are taken and averaged, apply the monthly average GCV value to the entire month; or

(2) If an assumed value (contract maximum or highest value from previous year's samples) is to be used in the calculations, apply the assumed value to all hours in each month of the quarter unless a higher value is obtained in a monthly GCV sample (or, if multiple samples are taken and averaged, if the monthly average exceeds the assumed value). In that case, if only one monthly sample is taken, use the sampled value, starting from the date on which the sample was taken. If multiple samples are taken and averaged, use the average value for the entire month in which the assumed value was exceeded. Consider the sample (or, if applicable, monthly average) results to be the new assumed value. Continue using the new assumed value unless and until one of the following occurs (as applicable to the reporting option selected): The assumed value is superseded by a higher value from a subsequent monthly sample (or by a higher monthly average); or the assumed value is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or both the calendar year in which the new sampled value (or monthly average) exceeded the assumed value and the subsequent calendar year have elapsed.

* * * * *

3.2.2 Convert density, specific gravity, or API gravity of the oil sample to density of the oil sample at the sampling location's temperature using ASTM D1250–07, Standard Guide for Use of the Petroleum Measurement Tables (incorporated by reference under (§ 75.6 of this part).

* * * * *

3.5.1 Hourly SO_2 Mass Emissions from the Combustion of all Fuels. Determine the total mass emissions for each hour from the combustion of all fuels using Equation D–12 (On and after January 1, 2009, determine the total mass emission rate (in lbs/hr) for each hour from the combustion of all fuels by dividing Equation D–12 by the actual unit operating time for the hour):

$$M_{So2-hr} = \sum_{all-fuels} SO2_{rate-I}\, t_i \qquad \text{(Eq. D-12)}$$

Where:

MSO_2-hr = Total mass of SO_2 emissions from all fuels combusted during the hour, lb.

SO_2 rate – I = SO_2 mass emission rate for each type of gas or oil fuel combusted during the hour, lb/hr.

ti = Time each gas or oil fuel was combusted for the hour (fuel usage time), fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

* * * * *

■ 43. Appendix E to part 75 is amended by:
■ a. Adding a new sentence to the end of section 2.1;
■ b. Revising the seventh sentence of section 2.1.2.1;
■ c. Revising sections 2.1.2.2 and 2.1.2.3;
■ d. Removing the phrase "(MWge or steam load in 1000 lb/hr)" and adding in its place the phrase "(MWge or steam load in 1000 lb/hr, or mmBtu/hr thermal output)", in section 2.4.1;
■ e. Revising section 2.5.2; and
■ f. Adding section 2.5.2.4.

The revisions and additions read as follows:

Appendix E to Part 75—Optional NO_X Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units

* * * * *

2.1 *Initial Performance Testing*

* * * The requirements in section 6.1.2 of appendix A to this part shall be met by any Air Emissions Testing Body (AETB) performing O_2 and NO_X concentration measurements under this appendix, either for units using the excepted methodology in this appendix or for units using the low mass emissions excepted methodology in § 75.19.

* * * * *

2.1.2.1 * * * Use a minimum of 12 sample points, located according to Method 1 in appendix A–1 to part 60 of this chapter.

* * * * *

2.1.2.2 For stationary gas turbines, sample at a minimum of 12 points per run at each load level. Locate the sample points according to Method 1 in appendix A–1 to part 60 of this chapter. For each fuel or consistent combination of fuels (and, optionally, for each combination of fuels), measure the NO_X and O_2 concentrations at each sampling point using methods 7E and 3A in appendices A–4 and A–2 to part 60 of this chapter. For diesel or dual fuel reciprocating engines, select the sampling site to be as close as practicable to the exhaust of the engine.

2.1.2.3 Allow the unit to stabilize for a minimum of 15 minutes (or longer if needed for the NO_X and O_2 readings to stabilize) prior to commencing NO_X, O_2, and heat input measurements. Determine the measurement system response time according to sections 8.2.5 and 8.2.6 of method 7E in appendix A–4 to part 60 of this chapter. When inserting the probe into the flue gas for the first sampling point in each traverse, sample for at least one minute plus twice the measurement system response time (or longer, if necessary to obtain a stable reading). For all other sampling points in each traverse, sample for at least one minute plus the measurement system response time (or longer, if necessary to obtain a stable reading). Perform three test runs at each load condition and obtain an arithmetic average of the runs for each load condition. During each test run on a boiler, record the boiler excess oxygen level at 5 minute intervals.

* * * * *

2.5.2 Substitute missing NO_X emission rate data using the highest NO_X emission rate tabulated during the most recent set of baseline correlation tests for the same fuel or, if applicable, combination of fuels, except as provided in sections 2.5.2.1, 2.5.2.2, 2.5.2.3, and 2.5.2.4 of this appendix.

* * * * *

2.5.2.4 Whenever 20 full calendar quarters have elapsed following the quarter of the last baseline correlation test for a particular type of fuel (or fuel mixture), without a subsequent baseline correlation test being done for that type of fuel (or fuel mixture), substitute the fuel-specific NO_X MER (as defined in § 72.2 of this chapter) for each hour in which that fuel (or mixture) is combusted until a new baseline correlation test for that fuel (or mixture) has been successfully completed. For fuel mixtures, report the highest of the individual MER values for the components of the mixture.

* * * * *

■ 44. Appendix F to Part 75 is amended by:
■ a. Removing the second and third sentences from the introductory text of section 2;
■ b. Removing the phrase "method 19 in appendix A of part 60 of this chapter" and adding in its place the phrase "Method 19 in appendix A–7 to part 60 of this chapter", in the last sentence of section 3.1 and in the last sentence of section 3.2;
■ c. Adding the phrase ", or (if applicable) in the equations in Method 19 in appendix A–7 to part 60 of this chapter" after the words "of this appendix", in section 3.3;
■ d. Removing the second and third sentences from section 3.3.4;
■ e. Adding sections 3.3.4.1 and 3.3.4.2;
■ f. Revising Table 1;
■ g. Revising the text preceding Equation F–7a, in section 3.3.6;
■ h. Revising section 3.3.6.1;
■ i. Revising section 3.3.6.2;
■ j. Revising sections 3.3.6.3 and 3.3.6.4;
■ k. Adding section 3.3.6.5;
■ l. Adding the words "either measured directly with a CO_2 monitor or calculated from wet-basis O_2 data using Equation F–14b," after the words "wet basis," in the first sentence of the C_h variable definition, and by removing the second and third sentences from the C_h variable definition, in section 4.1;
■ m. Revising section 4.4.1;
■ n. Removing the second and third sentences from the $\%CO_{2w}$ variable definition in 5.2.1;
■ o. Removing the second and third sentences from the $\%CO_{2d}$ variable definition in 5.2.2;
■ p. Removing the second and third sentences from the $\%O_{2w}$ variable definition, and by adding a new sentence at the end of the paragraph, in section 5.2.3;
■ q. Removing the second and third sentences from the $\%O_{2d}$ variable definition, in section 5.2.4;
■ r. Revising the definition of "GCV_o" in paragraph (a) of section 5.5.1;
■ s. Revising the definition of "GCV_g" in section 5.5.2;
■ t. Revising section 5.5.3.1;
■ u. Revising section 5.5.3.2;
■ v. Removing the phrase "as measured by ASTM D3176–89, D1989–92, D3286–91a, or D2015–91, Btu/lb" and adding in its place the phrase "as measured by ASTM D3176–89 (Reapproved 2002), or ASTM D5865–01a, Btu/lb. (incorporated by reference under § 75.6 of this part)." in the definition of the GCV_c variable in Equation F–21;
■ w. Removing the word "lb/hr" and adding in its place the phrase "lb/hr, or mmBtu/hr" in the definition of the SF variable in Equation F–21b;
■ x. Revising the heading and text of section 7;
■ y. Adding the words "of this appendix" after the words "section 8.1, 8.2, or 8.3" and after the words "section 8.4" in the introductory text for section 8;
■ z. Revising sections 8.1 and 8.1.1;
■ aa. Revising section 8.2;
■ bb. Adding sections 8.2.1 and 8.2.2;
■ cc. Revising section 8.3;
■ dd. Revising section 8.4; and
■ ee. Adding section 10.

The revisions and additions read as follows:

Appendix F to Part 75—Conversion Procedures.

* * * * *

3.3.4 * * *

3.3.4.1 For boilers, a minimum concentration of 5.0 percent CO_2 or a maximum concentration of 14.0 percent O_2 may be substituted for the measured diluent gas concentration value for any operating hour in which the hourly average CO_2 concentration is < 5.0 percent CO_2 or the hourly average O_2 concentration is > 14.0 percent O_2. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 or a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values for any operating hour in which the hourly average CO_2 concentration is < 1.0 percent CO_2 or the hourly average O_2 concentration is > 19.0 percent O_2.

3.3.4.2 If NO_X emission rate is calculated using either Equation 19–3 or 19–5 in Method 19 in appendix A–7 to part 60 of this chapter, a variant of the equation shall be used whenever the diluent cap is applied. The modified equations shall be designated as Equations 19–3D and 19–5D, respectively.

Equation 19–3D is structurally the same as Equation 19–3, except that the term "$\%O_{2w}$" in the denominator is replaced with the term "$\%O_{2dc} \times [(100 - \%\ H_2O)/100]$", where $\%O_{2dc}$ is the diluent cap value. The numerator of Equation 19–5D is the same as Equation 19–5; however, the denominator of Equation 19–5D is simply "$20.9 - \%O_{2dc}$", where $\%O_{2dc}$ is the diluent cap value.

* * * * *

TABLE 1.—F- AND F_c-FACTORS [1]

Fuel	F-factor (dscf/mmBtu)	F_C-factor (scf CO_2/mmBtu)
Coal (as defined by ASTM D388–99 [2]):		
Anthracite	10,100	1,970
Bituminous	9,780	1,800
Subbituminous	9,820	1,840
Lignite	9,860	1,910
Petroleum Coke	9,830	1,850
Tire Derived Fuel	10,260	1,800
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		
Bark	9,600	1,920
Wood residue	9,240	1,830

[1] Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.
[2] Incorporated by reference under § 75.6 of this part.

* * * * *

3.3.6 Equations F–7a and F–7b may be used in lieu of the F or F_c factors specified in Section 3.3.5 of this appendix to calculate a site-specific dry-basis F factor (dscf/mmBtu) or a site-specific F_c factor (scf CO_2/mmBtu), on either a dry or wet basis. At a minimum, the site-specific F or F_c factor must be based on 9 samples of the fuel. Fuel samples taken during each run of a RATA are acceptable for this purpose. The site-specific F or F_c factor must be re-determined at least annually, and the value from the most recent determination must be used in the emission calculations. Alternatively, the previous F or F_c value may continue to be used if it is higher than the value obtained in the most recent determination. The owner or operator shall keep records of all site-specific F or F_c determinations, active for at least 3 years. (Calculate all F- and F_c factors at standard conditions of 20 °C (68 °F) and 29.92 inches of mercury).

* * * * *

3.3.6.1 H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as the gross calorific value (GCV) by ultimate analysis of the fuel combusted using ASTM D3176–89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke, (solid fuels), ASTM D5291–02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, (liquid fuels) or computed from results using ASTM D1945–96 (Reapproved 2001), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, or ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography, (gaseous fuels) as applicable. (All of these methods are incorporated by reference under § 75.6 of this part.)

3.3.6.2 GCV is the gross calorific value (Btu/lb) of the fuel combusted determined by ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke, and ASTM D240–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, or ASTM D4809–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) for oil; and ASTM D3588–98, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, GPA Standard 2172–96 Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, GPA Standard 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, or ASTM D1826–94 (Reapproved 1998), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, for gaseous fuels, as applicable. (All of these methods are incorporated by reference under § 75.6 of this part).

3.3.6.3 For affected units that combust a combination of a fuel (or fuels) listed in Table 1 in section 3.3.5 of this appendix with any fuel(s) not listed in Table 1, the F or F_c value is subject to the Administrator's approval under § 75.66.

3.3.6.4 For affected units that combust combinations of fuels listed in Table 1 in section 3.3.5 of this appendix, prorate the F or F_c factors determined by section 3.3.5 or 3.3.6 of this appendix in accordance with the applicable formula as follows:

$$F=\sum_{i=1}^{n} X_i F_i \qquad F_c=\sum_{i=1}^{n} X_i (F_c)_i$$

Where,

X_i = Fraction of total heat input derived from each type of fuel (*e.g.*, natural gas, bituminous coal, wood). Each X_i value shall be determined from the best available information on the quantity of fuel combusted and the GCV value, over a specified time period. The owner or operator shall explain the method used to calculate X_i in the hardcopy portion of the monitoring plan for the unit. The X_i values may be determined and updated either hourly, daily, weekly, or monthly. In all cases, the prorated F-factor used in the emission calculations shall be determined using the X_i values from the most recent update.

F_i or $(F_c)_i$ = Applicable F or Fc factor for each fuel type determined in accordance with Section 3.3.5 or 3.3.6 of this appendix.

n = Number of fuels being combusted in combination.

3.3.6.5 As an alternative to prorating the F or Fc factor as described in section 3.3.6.4 of this appendix, a "worst-case" F or F_c factor may be reported for any unit operating hour.

The worst-case F or F_c factor shall be the highest F or F_c value for any of the fuels combusted in the unit.

* * * * *

4. Procedure for CO_2 Mass Emissions

* * * * *

4.4.1 If the owner or operator elects to use data from an O_2 monitor to calculate CO_2 concentration, the appropriate F and F_C factors from section 3.3.5 of this appendix shall be used in one of the following equations (as applicable) to determine hourly average CO_2 concentration of flue gases (in percent by volume) from the measured hourly average O_2 concentration:

$$CO_{2d} = 100 \frac{F_c}{F} \frac{20.9 - O_{2d}}{20.9} \qquad \text{(Eq. F-14a)}$$

Where:

CO_{2d} = Hourly average CO_2 concentration during unit operation, percent by volume, dry basis.

F, F_C = F-factor or carbon-based F_c-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O_2 in ambient air.

O_{2d} = Hourly average O_2 concentration during unit operation, percent by volume, dry basis.

$$CO_{2w} = \frac{100}{20.9} \frac{F_c}{F} \left[20.9 \left(\frac{100 - \%H_2O}{100} \right) - O_{2w} \right] \qquad \text{(Eq. F-14b)}$$

Where:

CO_{2w} = Hourly average CO_2 concentration during unit operation, percent by volume, wet basis.

O_{2w} = Hourly average O_2 concentration during unit operation, percent by volume, wet basis.

F, F_c = F-factor or carbon-based FC-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O_2 in ambient air.

$\%H_2O$ = Moisture content of gas in the stack, percent.

For any hour where Equation F–14a or F–14b results in a negative hourly average CO_2 value, 0.0% CO_{2w} shall be recorded as the average CO_2 value for that hour.

* * * * *

5. Procedures for Heat Input

* * * * *

5.2.3 * * * For any operating hour where Equation F–17 results in an hourly heat input rate that is ≤ 0.0 mmBtu/hr, 1.0 mmBtu/hr shall be recorded and reported as the heat input rate for that hour.

* * * * *

5.5.1 (a) * * *

GCV_o = Gross calorific value of oil, as measured by ASTM D240–00, ASTM D5865–01a, or ASTM D4809–00 for each oil sample under section 2.2 of appendix D to this part, Btu/unit mass (all incorporated by reference under (§ 75.6 of this part).

* * * * *

5.5.2 * * *

GCV_g = Gross calorific value of gaseous fuel, as determined by sampling (for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, for each hourly average for gas measured hourly with a gas chromatograph, or for each monthly sample of pipeline natural gas, or as verified by the contractual supplier at least once every month pipeline natural gas is combusted, as specified in section 2.3 of appendix D to this part) using ASTM D1826–94 (Reapproved 1998), ASTM D3588–98, ASTM D4891–89 (Reapproved 2006), GPA Standard 2172–96 Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, or GPA Standard 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, Btu/100 scf (all incorporated by reference under § 75.6 of this part).

* * * * *

5.5.3.1 Perform coal sampling daily according to section 5.3.2.2 in Method 19 in appendix A to part 60 of this chapter and use ASTM D2234–00, Standard Practice for Collection of a Gross Sample of Coal, (incorporated by reference under § 75.6 of this part) Type I, Conditions A, B, or C and systematic spacing for sampling. (When performing coal sampling solely for the purposes of the missing data procedures in § 75.36, use of ASTM D2234–00 is optional, and coal samples may be taken weekly.)

5.5.3.2 All ASTM methods are incorporated by reference under § 75.6 of this part. Use ASTM D2013–01, Standard Practice for Preparing Coal Samples for Analysis, for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke. On-line coal analysis may also be used if the on-line analytical instrument has been demonstrated to be equivalent to the applicable ASTM methods under §§ 75.23 and 75.66.

* * * * *

7. Procedures for SO_2 Mass Emissions, Using Default SO_2 Emission Rates and Heat Input Measured by CEMS

The owner or operator shall use Equation F–23 to calculate hourly SO_2 mass emissions in accordance with § 75.11(e)(1) during the combustion of gaseous fuel, for a unit that uses a flow monitor and a diluent gas monitor to measure heat input, and that qualifies to use a default SO_2 emission rate under section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part. Equation F–23 may also be applied to the combustion of solid or liquid fuel that meets the definition of very low sulfur fuel in § 72.2 of this chapter, combinations of such fuels, or mixtures of such fuels with gaseous fuel, if the owner or operator has received approval from the Administrator under § 75.66 to use a site-specific default SO_2 emission rate for the fuel or mixture of fuels.

$$E_h = (ER)(HI) \qquad \text{(Eq. F-23)}$$

Where:

E_h = Hourly SO_2 mass emission rate, lb/hr.

ER = Applicable SO_2 default emission rate for gaseous fuel combustion, from section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part, or other default SO_2 emission rate for the combustion of very low sulfur liquid or solid fuel, combinations of such fuels, or mixtures of such fuels with gaseous fuel, as approved by the Administrator under § 75.66, lb/mmBtu.

HI = Hourly heat input rate, determined using the procedures in section 5.2 of this appendix, mmBtu/hr.

8. Procedures for NO_X Mass Emissions

* * * * *

8.1 The own or operator may use the hourly NO_X emission rate and the hourly heat input rate to calculate the NO_X mass emissions in pounds or the NO_X mass emission rate in pounds per hour, (as required by the applicable reporting format), for each unit or stack operating hour, as follows:

8.1.1 If both NO_X emission rate and heat input rate are monitored at the same unit or stack level (e.g., the NO_X emission rate value and the heat input rate value both represent all of the units exhausting to the common stack), then (as required by the applicable reporting format) either:

(a) Use Equation F–24 to calculate the hourly NO_X mass emissions (lb).

$$M_{(NOx)_h} = ER_{(NOx)_h} HI_h t_h \qquad \text{(Eq. F-24)}$$

Where:

$M_{(NOx)_h}$ = NO_X mass emissions in lbs for the hour.

$ER_{(NOx)_h}$ = Hourly average NO_X emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from Method 19 in appendix A–7 to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NO_X emission rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

HI_h = Hourly average heat input rate for hour h, mmBtu/hr. (Include bias-adjusted flow rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

t_h = Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). If the combined NO_X emission rate and heat input are monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack; or

(b) Use Equation F–24a to calculate the hourly NO_X mass emission rate (lb/hr).

$$E_{(NOx)_h} = ER_{(NOx)_h} HI_h \qquad \text{(Eq. F-24a)}$$

Where:

$E_{(NOx)h}$ = NO_X mass emissions rate in lbs/hr for the hour.

$ER_{(NOx)h}$ = Hourly average NO_X emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from Method 19 in appendix A–7 to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NO_X emission rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

HI_h = Hourly average heat input rate for hour h, mmBtu/hr. (Include bias-adjusted flow rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

* * * * *

8.2 Alternatively, the owner or operator may use the hourly NO_X concentration (as measured by a NO_X concentration monitoring system) and the hourly stack gas volumetric flow rate to calculate the NO_X mass emission rate (lb/hr) for each unit or stack operating hour, in accordance with section 8.2.1 or 8.2.2 of this appendix (as applicable). If the hourly NO_X mass emissions are to be reported in lb, Equation F–26c in section 8.3 of this appendix shall be used to convert the hourly NO_X mass emission rates to hourly NO_X mass emissions (lb).

8.2.1 When the NO_X concentration monitoring system measures on a wet basis, first calculate the hourly NO_X mass emission rate (in lb/hr) during unit (or stack) operation, using Equation F–26a. (Include bias-adjusted flow rate or NO_X concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

$$E_{(NOx)_h} = K\ C_{hw} Q_h \qquad \text{(Eq. F-26a)}$$

Where:

$E_{(NOx)h}$ = NO_X mass emissions rate in lb/hr.

$K = 1.194 \times 10^{-7}$ for NO_X, (lb/scf)/ppm.

C_{hw} = Hourly average NO_X concentration during unit operation, wet basis, ppm.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

8.2.2 When NO_X mass emissions are determined using a dry basis NO_X concentration monitoring system and a wet basis flow monitoring system, first calculate hourly NO_X mass emission rate (in lb/hr) during unit (or stack) operation, using Equation F–26b. (Include bias-adjusted flow rate or NO_X concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

$$E_{(NO_X)_h} = K\ C_{hd} Q_h \frac{(100 - \%H_2O)}{(100)} \qquad \text{(Eq. F-26b)}$$

Where:

$E_{(NOx)h}$ = NO_X mass emissions rate, lb/hr.

$K = 1.194 \times 10^{-7}$ for NO_X, (lb/scf)/ppm.

C_{hd} = Hourly average NO_X concentration during unit operation, dry basis, ppm.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

$\%H_2O$ = Hourly average stack moisture content during unit operation, percent by volume.

8.3 When hourly NO_X mass emissions are reported in pounds and are determined using a NO_X concentration monitoring system and a flow monitoring system, calculate NO_X mass emissions (lb) for each unit or stack operating hour by multiplying the hourly NO_X mass emission rate (lb/hr) by the unit operating time for the hour, as follows:

$$M_{(NO_X)_h} = E_h t_h \qquad \text{(Eq. F-26c)}$$

Where:

$M_{(NOx)h}$ = NO_X mass emissions for the hour, lb.

E_h = Hourly NO_X mass emission rate during unit (or stack) operation from Equation F–26a in section 8.2.1 of this appendix or Equation F–26b in section 8.2.2 of this appendix (as applicable), lb/hr.

t_h = Unit operating time or stack operating time (as defined in § 72.2 of this chapter) for hour "h", in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

8.4 Use the following procedures to calculate quarterly, cumulative ozone season, and cumulative yearly NO_X mass emissions, in tons:

(a) When hourly NO_X mass emissions are reported in lb., use Eq. F–27.

$$M_{(NO_X)_{\text{time period}}} = \frac{\sum_{h=1}^{p} M(NO_X)_h}{2000} \qquad \text{(Eq. F-27)}$$

Where:

$M_{(NOx)\text{time period}}$ = NO_X mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$M_{(NOx)h}$ = NO_X mass emissions in lb for the hour.

p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

(b) When hourly NO_X mass emission rate is reported in lb/hr, use Eq. F–27a.

$$M_{(NO_X)_{\text{time period}}} = \frac{\sum_{h=1}^{p} E_{(NO_X)_h} t_h}{2000} \qquad \text{(Eq. F-27a)}$$

Where:

$M_{(NO_X)_{time\ period}}$ = NO_X mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$E_{(NO_X)_h}$ = NO_X mass emission rate in lb/hr for the hour.

p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

t_h = Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

* * * * *

10. Moisture Determination From Wet and Dry O_2 Readings

If a correction for the stack gas moisture content is required in any of the emissions or heat input calculations described in this appendix, and if the hourly moisture content is determined from wet- and dry-basis O_2 readings, use Equation F–31 to calculate the percent moisture, unless a "K" factor or other mathematical algorithm is developed as described in section 6.5.7(a) of appendix A to this part:

$$\%H_2O = \frac{(O_{2d} - O_{2w})}{O_{2d}} \times 100 \qquad \text{(Eq. F-31)}$$

Where:

% H_2O = Hourly average stack gas moisture content, percent H_2O

O_{2d} = Dry-basis hourly average oxygen concentration, percent O_2

O_{2w} = Wet-basis hourly average oxygen concentration, percent O_2

■ 45. Appendix G to Part 75 is amended by:

■ a. Revising section 2.1.2;

■ b. Removing "D3174–89 'Standard Test Method for Ash in the Analysis Sample of Coal and Coke From Coal' " and by adding in its place, "D3174–00, Standard Test Method for Ash in the Analysis Sample of Coal and Coke from Coal" in section 2.2.1; and

■ c. Removing "D3178–89 (1997), 'Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke' " and adding in its place "D5373–02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke" in section 2.2.2.

The revisions read as follows:

Appendix G to Part 75—Determination of CO_2 Emissions.

* * * * *

2.1.2 Determine the carbon content of each fuel sample using one of the following methods: ASTM D3178–89 (Reapproved 2002) or ASTM D5373–02 (Reapproved 2007) for coal; ASTM D5291–02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, ultimate analysis of oil, or computations based upon ASTM D3238–95 (Reapproved 2000) and either ASTM D2502–92 (Reapproved 1996) or ASTM D2503–92 (Reapproved 1997) for oil; and computations based on ASTM D1945–96 (Reapproved 2001) or ASTM D1946–90 (Reapproved 2006) for gas (all incorporated by reference under § 75.6 of this part).

* * * * *

■ 46. Appendix K to Part 75 is amended by:

■ a. Removing the words "(see §§ 75.11(b) and 75.12(b))" and adding in its place the words "(see § 75.11(b))" in section 5;

■ b. Adding a sentence to the end of section 7.2.3;

■ c. Removing the words "or § 75.12(b)" and "or § 75.12," from section 7.2.4;

■ d. Revising Table K–1 of section 8; and

■ e. Adding the words "or in Table K–1" following the words "§ 75.15(h)" in the second sentence of section 11.8.

The revisions and additions read as follows:

Appendix K to Part 75—Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems

* * * * *

7.2.3 * * * The sample flow rate through a sorbent trap monitoring system during any hour (or portion of an hour) in which the unit is not operating shall be zero.

* * * * *

TABLE K–1.—QUALITY ASSURANCE/QUALITY CONTROL CRITERIA FOR SORBENT TRAP MONITORING SYSTEMS

QA/QC test or specification	Acceptance criteria	Frequency	Consequences if not met
Pre-test leak check	≤4% of target sampling rate	Prior to sampling	Sampling shall not commence until the leak check is passed.
Post-test leak check	≤4% of average sampling rate	After sampling	** See *Note*, below.
Ratio of stack gas flow rate to sample flow rate.	No more than 5% of the hourly ratios or 5 hourly ratios (whichever is less restrictive) may deviate from the reference ratio by more than ± 25%.	Every hour throughout data collection period.	** See *Note*, below.
Sorbent trap section 2 breakthrough.	≤5% of Section 1 Hg mass	Every sample	** See *Note*, below.
Paired sorbent trap agreement	≤10% Relative Deviation (RD) if the average concentration is > 1.0 μg/m³. ≤ 20% RD if the average concentration is ≤ 1.0 μg/m³. Results are also acceptable if absolute difference between concentrations from paired traps is ≤ 0.03 μg/m³.	Every sample	Either invalidate the data from the paired traps or report the results from the trap with the higher Hg concentration.
Spike Recovery Study	Average recovery between 85% and 115% for each of the 3 spike concentration levels.	Prior to analyzing field samples and prior to use of new sorbent media.	Field samples shall not be analyzed until the percent recovery criteria has been met
Multipoint analyzer calibration	Each analyzer reading within ± 10% of true value and $r^2 \geq 0.99$.	On the day of analysis, before analyzing any samples.	Recalibrate until successful.

TABLE K–1.—QUALITY ASSURANCE/QUALITY CONTROL CRITERIA FOR SORBENT TRAP MONITORING SYSTEMS—Continued

QA/QC test or specification	Acceptance criteria	Frequency	Consequences if not met
Analysis of independent calibration standard.	Within ± 10% of true value	Following daily calibration, prior to analyzing field samples.	Recalibrate and repeat independent standard analysis until successful.
Spike recovery from section 3 of sorbent trap.	75–125% of spike amount	Every sample	** See *Note*, below.
RATA	RA ≤ 20.0% *or* Mean difference ≤ 1.0 µg/dscm for low emitters.	For initial certification and annually thereafter.	Data from the system are invalidated until a RATA is passed.
Gas flow meter calibration	Calibration factor (Y) within ± 5% of average value from the most recent 3-point calibration.	At three settings prior to initial use and at least quarterly at one setting thereafter. For mass flow meters, initial calibration with stack gas is required.	Recalibrate the meter at three orifice settings to determine a new value of Y.
Temperature sensor calibration	Absolute temperature measured by sensor within ± 1.5% of a reference sensor.	Prior to initial use and at least quarterly thereafter.	Recalibrate. Sensor may not be used until specification is met.
Barometer calibration	Absolute pressure measured by instrument within ± 10 mm Hg of reading with a mercury barometer.	Prior to initial use and at least quarterly thereafter.	Recalibrate. Instrument may not be used until specification is met.

** Note: If both traps fail to meet the acceptance criteria, the data from the pair of traps are invalidated. However, if only one of the paired traps fails to meet this particular acceptance criterion and the other sample meets all of the applicable QA criteria, the results of the valid trap may be used for reporting under this part, provided that the measured Hg concentration is multiplied by a factor of 1.111. When the data from both traps are invalidated and quality-assured data from a certified backup monitoring system, reference method, or approved alternative monitoring system are unavailable, missing data substitution must be used.

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[FR Doc. E7–25071 Filed 1–23–08; 8:45 am]

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Corrections

Federal Register
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This section of the FEDERAL REGISTER contains editorial corrections of previously published Presidential, Rule, Proposed Rule, and Notice documents. These corrections are prepared by the Office of the Federal Register. Agency prepared corrections are issued as signed documents and appear in the appropriate document categories elsewhere in the issue.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA-HQ-OAR-2005-0526; FRL-8508-6]

RIN 2060-AN21

National Emission Standards for Hazardous Air Pollutants: Paint Stripping and Miscellaneous Surface Coating Operations at Area Sources

Correction

In rule document E7–24718 beginning on page 1738 in the issue of Wednesday, January 9, 2008, make the following corrections:

§ 63.11173 [Corrected]

1. On page 1761, in the second column, in § 63.11173(b), in the seventh line from the bottom, "more" should read "less".

2. On the same page, in the same column, in the same section, in the same paragraph, in the fifth line from the bottom, "management practices" should read "requirements".

[FR Doc. Z7–24718 Filed 2–12–08; 8:45 am]

BILLING CODE 1505–01–D

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 75

[EPA–HQ–OAR–2005–0132; FRL–8511–1]

RIN 2060–AN16

Revisions to the Continuous Emissions Monitoring Rule for the Acid Rain Program, NO_x Budget Trading Program, Clean Air Interstate Rule, and the Clean Air Mercury Rule

Correction

In rule document E7–25071 beginning on page 4312 in the issue of Thursday, January 24, 2008 make the following correction:

Appendix F to Part 75 [Corrected]

On page 4373, the equation should read as set forth below:

$$F = \sum_{i=1}^{n} X_i F_i \qquad F_c = \sum_{i=1}^{n} X_i \left(F_c\right)_i \qquad \text{(Eq. F-8)}$$

[FR Doc. Z7–25071 Filed 2–12–08; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 97

[EPA-R05-OAR-2007-0390; FRL-8519-6]

Approval and Promulgation of Air Quality Implementation Plans; Ohio; Clean Air Interstate Rule

Correction

In rule document E8–1804 beginning on page 6034 in the issue of Friday, February 1, 2008, make the following corrections:

Appendix A to Subpart IIII of Part 97 [Corrected]

1. On page 6041, in the first column, in amendatory instruction 8, in the first line, "Appendix A to Subpart IV" should read "Appendix A to Subpart IIII".

2. On the same page, in the same column, in the last appendix heading, in the first line, "**Appendix A to Subpart IV of Part 97**" should read "**Appendix A to Subpart IIII of Part 97**".

[FR Doc. Z8–1804 Filed 2–12–08; 8:45 am]

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DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

49 CFR Part 563

[Docket No. NHTSA-2008-0004]

RIN 2127-AK12

Event Data Recorders

Correction

In rule document E8–407 beginning on page 2168 in the issue of Monday, January 14, 2008, make the following correction:

§563.7 [Corrected]

On page 2182, in §563.7(b), Table II is corrected to read as follows:

TABLE II.—DATA ELEMENTS REQUIRED FOR VEHICLES UNDER SPECIFIED MINIMUM CONDITIONS

Data element name	Condition for requirement	Recording interval/time [1] (relative to time zero)	Data sample rate (per second)
Lateral acceleration	If recorded [2]	0 to 250 ms	100
Longitudinal acceleration	If recorded	0 to 250 ms	100