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Part III

Environmental Protection Agency

40 CFR Part 60

Standards of Performance for Fossil-Fuel-Fired Steam Generators; Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2005-0031; FRL-8748-2]

RIN 2060-AO61

Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971; Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978; Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units; and Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is amending the new source performance standards (NSPS) for electric utility steam generating units and industrial-commercial-institutional steam generating units. These amendments to the regulations are to add compliance alternatives for owners and operators of certain affected sources, eliminate the opacity standard for facilities with a particulate matter (PM) limit of 0.030 lb/million British thermal units (MMBtu) or less that choose to voluntarily install and use PM continuous emission monitors (CEMS) to demonstrate compliance with that limit, and to correct technical and editorial errors.

DATES: This final rule is effective on January 28, 2009. The incorporation by reference of certain publications listed in this final rule is approved by the Director of the Federal Register as of January 28, 2009.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA-HQ-OAR-2005-0031. All documents in the docket are listed in the Federal Docket Management System index at <http://www.regulations.gov>. Although listed in the index, some information is not publicly available, e.g., confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through <http://www.regulations.gov> or in hard copy at the EPA Docket Center, Public Reading Room, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the Air Docket is (202) 566-1742.

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SUPPLEMENTARY INFORMATION: *Outline.* The information presented in this preamble is organized as follows:

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I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by this final action include, but are not limited to, the following:

Category	NAICS Code ¹	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal Government	22112	Fossil fuel-fired electric utility steam generating units owned by the Federal Government.
State/local/ tribal government	22112	Fossil fuel-fired electric utility steam generating units owned by municipalities.
Any industrial, commercial, or institutional facility using a steam generating unit as defined in 60.40b or 60.4c.	921150	Fossil fuel-fired electric steam generating units in Indian Country.
	211	Extractors of crude petroleum and natural gas.
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refiners and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational services.

¹ North American Industry Classification System (NAICS) code.

This table is not intended to be exhaustive, but rather provides a guide

for readers regarding entities likely to be regulated by this action. To determine

whether your facility is regulated by this action, you should examine the

applicability criteria in § 60.40, § 60.40a, § 60.40b, or § 60.40c of 40 CFR part 60. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permit authority for the entity or your EPA regional representative as listed in § 63.13 of subpart A (General Provisions) of title 40 of the Code of Federal Regulations.

B. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this final action will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of this final action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: <http://www.epa.gov/ttn/oarpg/>. The TTN provides information and technology exchange in various areas of air pollution control.

C. Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of these final rules is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by March 30, 2009. Under section 307(d)(7)(B) of the CAA, only an objection to these final rules that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by these final rules may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

II. Background Information

In response to petitions for reconsideration of the amendments to the new source performance standards for steam generating units that EPA promulgated on June 13, 2007 (72 FR 32710) filed by the Coke Oven Environmental Task Force, EPA proposed revised amendments to address issues for which the petitioners requested reconsideration (see docket entry EPA-HQ-OAR-2005-0031-0276). EPA also proposed certain other unrelated amendments it felt were appropriate. In sum, EPA proposed on June 12, 2008 (73 FR 33642) to amend subparts D, Da, Db, and Dc of 40 CFR part 60 to clarify the intent for applying and implementing specific rule requirements, provide additional compliance alternatives, and to correct unintentional technical omissions and editorial errors.

A 45-day comment period (June 12, 2008 to July 28, 2008) was provided to accept comments on the proposed rule. An opportunity for a public hearing was provided to allow any interested persons to present oral comments on the proposed rule. However, EPA did not receive a request for a formal public hearing, so a public hearing was not held. We received comments on the proposed amendments from 11 commenters during the comment period.

III. Final Amendments and Response to Public Comments

We are amending subparts D, Da, Db, and Dc of 40 CFR part 60 to add compliance alternatives for owners/operators of certain affected sources, to eliminate the opacity standard for certain facilities voluntarily using PM CEMS, and to correct technical and editorial errors. These amendments address issues raised by the Coke Oven Environmental Task Force, including an alternate sulfur dioxide (SO₂) limit during SO₂ control system maintenance and allowing the use of parametric monitoring of nitrogen oxide (NO_x) emissions for owners and operators of coke oven gas-fired (COG) steam generating units. In addition, we are specifying the opacity monitoring requirements for owners and operators of all affected facilities that are subject to an opacity limit, including owner and operators of COG-fired steam generating units, but exempt from the continuous opacity monitoring system (COMS) requirement. This action promulgates the amended regulatory language as proposed, except for those significant provisions identified below.

We are also finalizing several clarifications to correct technical and editorial errors and to amend the monitoring requirements for owners and operators of affected facilities that elect to install particulate matter continuous emission monitoring systems (PM CEMS). Owners and operators of affected facilities that install a PM CEMS will be exempt from the opacity standard as long as they are complying with a federally enforceable permit limiting PM emissions to 0.030 pounds per million British thermal units or less. In addition, owner and operators of affected facilities that elect to install PM CEMS will be required to measure and report emissions of condensable PM.

Minor revisions to the proposed regulatory language were also made to clarify specific provisions or to correct unintentional technical omissions and terminology, typographical, printing, and grammatical errors that were identified in the proposed rule either as

a result of comments we received or based on our own subsequent review of the text. One change revises appropriate definitions and requirements in subpart Da to clarify the applicability and implementation of the subpart Da provisions to integrated coal gasification combined cycle electric utility power plants. Another change clarifies the fact that not all combined cycle facilities that burn solid derived fuels are subject to the subpart.

The final amendments promulgated by this action reflect EPA's consideration of the comments received on the proposal. EPA's responses to the substantive public comments on the proposal are presented in a comment summary and response document available in Docket ID No. EPA-HQ-OAR-2005-0031. A summary of selected public comments and our responses is as follows.

Comment: Several commenters generally support the exemption of affected facilities using PM CEMS from the opacity standard. However, the commenters requested that EPA exempt those affected facilities opting to use PM CEMS from the opacity standard without imposing conditions for additional condensable PM or opacity tests. The commenters stated the EPA's proposed method for measuring condensable PM (Method 202) is flawed and significantly overstates the amount of condensable PM, and noted that Method 202 itself condenses gaseous emissions that would not be condensing in the flue gas. They also noted that further improvements of Method 202 must be made before it is required as the method to measure condensable PM.

Response: The opacity standard and all opacity monitoring requirements have been eliminated for owner/operators of affected facilities complying with a federally enforceable PM limit of 0.030 lb/MMBtu or less who voluntarily elect to use a PM CEMS to demonstrate continuous compliance with the PM limit. The contribution of filterable PM to opacity at these emission levels is generally negligible, and sources with mass limits at this level or less will operate with little or no visible emissions (*i.e.* less than 5 percent opacity). As a result, EPA believes that an opacity standard is no longer necessary for these sources since the PM mass emission rate standard is substantially tighter than the opacity standard and the mass of PM emissions will be continually monitored.

We concluded, however, that it is only appropriate to eliminate the opacity standard and associated opacity monitoring for owners/operators of facilities complying with a PM limit of

0.030 lb/MMBtu or less. At this emission rate, the presence of visible emissions may indicate that the PM control device is not operating properly. This amended NSPS does not require any corrective action in such a case as long as the PM CEMS is complying with all applicable federal requirements. However, PM CEMS readings cannot be verified as readily as other CEMS, and since recalibration requires PM performance tests, baseline opacity readings can be a valuable secondary check on control device performance and PM emissions. The local permitting authority does have the discretion to require an investigation to determine the cause of the visible emissions. The presence of such emissions is not, however, necessarily evidence of a violation of the PM standard. In situations where the owner/operator of a facility has documented visible emissions during the initial or subsequent PM CEMS calibration testing or documented trends in PM CEMS readings that correlate to the visible emissions, the relative amount of visible emissions can still be used by the local permitting authority as a secondary check that both the PM control device and PM CEMS are operating properly. While these facilities will not be required to install continuous opacity monitoring systems (COMS), if a facility decided to or is required by the permitting authority to install a COMS, the data would be useful as a secondary check on PM emissions and proper operation of the PM control device and to verify that the PM CEMS is operating properly. Owners/operators of affected facilities with a PM limit greater than 0.030 lb/MMBtu that elect to install PM CEMS may have some visible emissions, will still be subject to an opacity limit, and will be required to either use a COMS or perform periodic visual inspections to comply with the opacity standard.

In addition, we have concluded it is appropriate to require condensable PM testing for owners/operators of affected facilities that elect to use PM CEMS to determine the contribution of condensable PM to total PM emissions. We will use this data to determine if the condensable PM emissions from steam generating units have a significant health and/or environmental impact and whether condensable PM should be included in future amendments to the PM standard. By early 2009, we intend to propose amendments to Method 202 that will address the concerns about artifact measurement. Since the rule will not be finalized until early in 2010, we are delaying the requirement to

perform condensable PM testing until July 1, 2010 or until Method 202 is revised to minimize artifact measurement, whichever is later.

Comment: Several commenters oppose increasing the Method 9 monitoring frequency. The commenters stated that increasing the frequency from annually to a weekly, monthly, or quarterly basis without identifying any particular issue of concern that might occur on a weekly, monthly, or quarterly basis is arbitrary, unnecessary, overly burdensome, and would provide little environmental benefit. In addition, one commenter supports the use of Method 22 as an alternative to Method 9 for those sources that are expected to have no significant visible emissions. However, three 1-hour Method 22 observations would actually take significantly longer than 3 hours. Under Method 22, observers are instructed not to continuously view emissions for more than 15–20 minutes at a time, and that breaks of 5–10 minutes should be taken between each observation. Following these criteria, each 1-hour observation would take at least one and a half hours. Finally, one commenter requested that EPA allow for owners/operators of affected facilities that comply with subpart D, Da, Db, or Dc, by the use of a fabric filter, the alternative of installing and operating triboelectric bag leak detectors as an alternative to using a COMS.

Response: We have concluded that the appropriate approach is to base the frequency of visible emissions monitoring on the level of visible emissions detected during the most recent observation. Owners/operators of facilities that elect to not use a COMS to demonstrate compliance with the opacity limit will conduct at least an initial Method 9 performance test. The frequency of the required subsequent Method 9 testing is based on the results of the highest 6-minute opacity observed during the most recent performance test. Owners/operators of affected facilities where the maximum 6-minute opacity reading is greater than 10 percent will be required to conduct monthly Method 9 performance testing; owners/operators of affected facilities where the maximum 6-minute opacity reading is between 5 percent and 10 percent will be required to conduct quarterly Method 9 performance testing; owners/operators of affected facilities with some visible emissions but where the maximum 6-minute opacity reading is 5 percent or less will be required to conduct semi-annual Method 9 performance testing; and owners/operators of affected facilities with no visible emissions will only be required

to conduct an annual Method 9 performance test.

As an alternative, owners/operators of affected facilities where maximum 6-minute opacity readings from the most recent Method 9 performance test is less than 10 percent may elect to use either Method 22 or the digital opacity monitoring system in lieu of subsequent Method 9 performance testing. The proposed amendments required a total of 3 hours of observation annually, but did not specify when or for how long those observations would be done. We have concluded it is appropriate to decrease the length of each observation to a minimum of 10 minutes, but to increase the frequency to daily observations. This approach both minimizes the burden of this option while increasing protection to the environment, as observations will be performed throughout the year. If an owner/operator of an affected facility observes visible emissions in excess of 5 percent during any observation and is unable to take corrective action, they will be required to either conduct a Method 9 performance test with the previously specified frequency or to install a COMS. To maintain consistency in the operation of the digital opacity monitoring system, the EPA Administrator will approve opacity monitoring plans for owners/operators that elect to use the digital opacity monitoring system to detect the presence of visible emissions.

Finally, we have concluded it is appropriate to allow owners/operators of affected facilities subject to subparts Da, Db, and Dc, and who install, maintain, and operate a bag leak detection system, the option to use periodic visual inspections of plume opacity as an alternative to monitoring opacity with a COMS. Modern baghouses often operate with no visible emissions, and a bag leak detection system will allow owners/operators to identify potential problems with the control device and repair the problems prior to increases in opacity.

Comment: Several commenters oppose the proposed requirement to electronically submit performance evaluation test data to EPA's WebFIRE database. One commenter stated that EPA has not: (1) Provided any rationale for requiring the data to be reported and entered electronically; (2) provided any information on the proposed reporting format or mechanism to allow interested parties to understand what sort of burden this requirement would impose and whether the requirement is more or less burdensome than other forms of reporting; or (3) provided any mechanism for sources to confirm the

authenticity of data submitted to this Web site for their facility. Furthermore, before EPA can impose any new reporting requirement, EPA must comply with the requirements of the Paperwork Reduction Act and also address whether the submission meets the requirements of the Cross-Media Electronic Reporting Rule (CROMERR), which is codified at 40 CFR part 3. Another commenter stated that any reporting should not be required of sources until the WebFIRE is fully operational. A formal regulation is not the proper venue to “troubleshoot” communications with an external database for the regulated community.

Response: EPA does not expect WebFIRE and the associated Electronic Reporting Tool (ERT) to be operational until early 2011, and we are delaying the requirement until July 1, 2011. We do not expect electronic submittal of performance test information to have any significant costs or impacts to industry (because we are not requiring additional testing or software and source testing companies already compile these data electronically), and since submission of data directly to EPA is only a requirement for facilities that voluntarily elect to use PM CEMS to demonstrate compliance with the PM limit, the ICR does not need to be amended. In addition, as an alternate to using the ERT we are allowing owner/operators to mail the test report directly to EPA. Finally, we fully expect the ERT to be compliant with CROMERR before reporting is required in 2011.

Comment: Two commenters requested that EPA reconsider the Agency’s decision to include direct contact water heaters in the definition of “steam generating unit” used for determining applicability of the requirements under subparts Db and Dc because it is contrary to previous EPA applicability determinations, and it is confusing to include water heaters in a regulation for steam generating units.

Response: The definition of steam generating unit includes direct contact water heaters and as such, these units meet the applicability of subpart Dc. However, we recognize that two source-specific letters exempt individual direct contact water heaters from the applicability of subpart Dc of 40 CFR part 60, and owners/operators of the units in question reasonably relied on these determinations and have not been complying with subpart Dc to date. We do not intend to reverse these source specific determinations or to require retroactive reporting for any owner/operators of similar facilities that relied on these determinations and have not been maintaining the proper records,

but we are clarifying and confirming that direct contact water heaters have always been subject to subpart Dc, and records shall be maintained from June 12, 2008 onward, consistent with the definition of steam generating unit.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a “significant regulatory action” because it may raise novel legal or policy issues arising out of legal mandates, the President’s priorities, or the principles set forth in the Executive Order. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. The final rule results in no changes to the information collection requirements of the existing standards of performance and will have no impact on the information collection estimate of projected cost and hour burden made and approved by the OMB during the development of the existing standards of performance. Therefore, the information collection requests have not been amended. However, OMB previously approved the information collection requirements contained in the existing regulations (subparts Da, Db, and Dc of 40 CFR part 60) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, and has assigned OMB control numbers 2060–0023 for subpart Da of 40 CFR part 60, 2060–0072 for subpart Db of 40 CFR part 60, and 2060–0202 for subpart Dc of 40 CFR part 60. OMB control numbers for EPA’s regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of the final amendments on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration’s regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant *adverse* economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives “which minimize any significant economic impact of the rule on small entities.” 5 U.S.C. 603 and 604. Thus, an agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule.

EPA is minimizing the opacity monitoring requirements for owner/operators of affected facilities subject to an opacity standard but exempt from the COMS requirement. We have therefore concluded that this final rule will relieve regulatory burden for all affected small entities.

D. Unfunded Mandates Reform Act

This rule does not change the overall cost of the rule and therefore does not contain a Federal mandate that may result in expenditures of \$100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Thus, this final rule is not subject to the requirements of sections 202 or 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This rule modifies previously established requirements and does not impose any new obligations or enforceable duties on any small governments.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled “Federalism” (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure “meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.” “Policies that have federalism implications” is defined in the Executive Order to include regulations that have “substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.”

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This action will not impose substantial direct compliance costs on State or local governments; it will not preempt State law. Thus, Executive Order 13132 does not apply to this rule.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). While utility steam generating units are located on tribal lands, EPA is not aware of any that are owned by tribal governments. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is based solely on technology performance.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a “significant energy action” as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. We have

concluded that this final rule is not likely to have any adverse energy effects because it generally only clarifies our intent and corrects errors in the existing rule.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (“NTTAA”), Public Law 104–113 (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This final rule involves technical standards. EPA has decided to use ASTM D975–08a, “Standard Specification for Diesel Fuel Oils,” for defining diesel fuel oil. This standard is available from the American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959.

EPA has also decided to use EPA Method 202 (40 CFR part 51, appendix M). The Agency has not found any alternative methods. The search and review results are in the docket for this regulation.

Under 40 CFR 60.13(i) of the NSPS General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications, or procedures in the final rule and amendments.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practical and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. This action does not change any emission limits and, therefore, does not affect the level of protection provided to human health or the environment.

H. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of Congress and to the Comptroller General of the United States. EPA will submit a report containing these final amendments and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the final rules in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a “major rule” as defined by 5 U.S.C. 804(2). This final rule will be effective on January 28, 2009.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: November 26, 2008.

Stephen L. Johnson,
Administrator.

Editorial Note: This document was received in the Office of the Federal Register on Thursday, January 8, 2009.

■ For the reasons stated in the preamble, title 40, chapter I, part 60 of the Code of Federal Regulations is amended as follows:

PART 60—[AMENDED]

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—[Amended]

■ 2. Section 60.17 is amended by redesignating paragraphs (a)(17) through (a)(92) as paragraphs (a)(18) through (a)(93) and by adding new paragraph (a)(17) to read as follows:

§ 60.17 Incorporations by Reference.

* * * * *

(a) * * *

(17) ASTM D975–08a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

Subpart D—[Amended]

■ 3. Section 60.42 is amended by adding paragraph (c) to read as follows:

§ 60.42 Standard for particulate matter (PM).

* * * * *

(c) As an alternate to meeting the requirements of paragraph (a) of this section, an owner or operator that elects to install, calibrate, maintain, and operate a continuous emissions monitoring systems (CEMS) for measuring PM emissions can petition the Administrator (in writing) to comply with § 60.42Da(a) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in § 60.43Da(a) of subpart Da of this part.

■ 4. Section 60.43 is amended by revising paragraph (d) to read as follows:

* * * * *

§ 60.43 Standard for sulfur dioxide (SO₂).

(d) As an alternate to meeting the requirements of paragraphs (a) and (b) of this section, an owner or operator can petition the Administrator (in writing) to comply with § 60.43Da(i)(3) of subpart Da of this part or comply with § 60.42b(k)(4) of subpart Db of this part, as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in § 60.43Da(i)(3) of subpart Da of this part or § 60.42b(k)(4) of subpart Db of this part, as applicable to the affected source.

■ 5. Section 60.45 is amended to read as follows:

- a. By revising paragraph (a);
- b. By revising paragraphs (b)(1) and (b)(6)(i)(C) and adding paragraph (b)(7);
- c. By revising paragraphs (g)(2), (g)(3), and (g)(4); and
- d. By adding paragraph (h).

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a

CEMS for measuring SO₂ emissions, NO_x emissions, and either oxygen (O₂) or carbon dioxide (CO₂) except as provided in paragraph (b) of this section.

(b) * * *

(1) For a fossil-fuel-fired steam generator that burns only gaseous or liquid fossil fuel (excluding residual oil) with potential SO₂ emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO₂ or PM, CEMS for measuring the opacity of emissions and SO₂ emissions are not required if the owner or operator monitors SO₂ emissions by fuel sampling and analysis or fuel receipts.

* * * * *

(6) * * *

(i) * * *

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

* * * * *

(7) The owner or operator of an affected facility subject to an opacity standard under § 60.42 and that elects to not install a COMS because the affected facility burns only fuels as specified under paragraph (b)(1) of this section, monitors PM emissions as specified under paragraph (b)(5) of this section, or monitors CO emissions as specified under paragraph (b)(6) of this section shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.42 and shall comply with either paragraphs (b)(7)(i), (b)(7)(ii), or (b)(7)(iii) of this section. If during the initial 60 minutes of observation all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent, the observation period may be reduced from 3 hours to 60 minutes.

(i) Except as provided in paragraph (b)(7)(ii) or (b)(7)(iii) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (b)(7) of this section according to the applicable schedule in paragraphs (b)(7)(i)(A) through (b)(7)(i)(D) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance

test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted; or

(D) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 30 calendar days from the date that the most recent performance test was conducted.

(ii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance test, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (b)(7)(ii)(A) and (B) of this section.

(A) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.*, 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.*, 90 seconds per 30 minute period) the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.*, 90 seconds) or conduct a new Method 9 of appendix A–4 of this part performance test using the procedures

in paragraph (b)(7) of this section within 30 calendar days according to the requirements in § 60.46(b)(3).

(B) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(iii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (b)(7)(ii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

* * * * *

(g) * * *

(2) *Sulfur dioxide*. Excess emissions for affected facilities are defined as:

(i) For affected facilities electing not to comply with § 60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO₂ as measured by a CEMS exceed the applicable standard in § 60.43; or

(ii) For affected facilities electing to comply with § 60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO₂ as measured by a CEMS exceed the applicable standard in § 60.43. Facilities complying with the 30-day SO₂ standard shall use the most current associated SO₂ compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part or §§ 60.45b and 60.47b of subpart Db of this part, as applicable.

(3) *Nitrogen oxides*. Excess emissions for affected facilities using a CEMS for measuring NO_x are defined as:

(i) For affected facilities electing not to comply with § 60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in § 60.44; or

(ii) For affected facilities electing to comply with § 60.44(e), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_x as measured by a CEMS exceed the applicable standard in § 60.44. Facilities complying with the 30-day NO_x standard shall use the most current associated NO_x compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part.

(4) *Particulate matter*. Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards in § 60.42. Affected facilities using PM CEMS must follow the most current applicable compliance and monitoring provisions in §§ 60.48Da and 60.49Da of subpart Da of this part.

(h) The owner or operator of an affected facility subject to the opacity limits in § 60.42 that elects to monitor emissions according to the requirements in § 60.45(b)(7) shall maintain records according to the requirements specified in paragraphs (h)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

■ 6. Section 60.46 is amended by revising paragraph (d)(2) to read as follows:

§ 60.46 Test methods and procedures.

* * * * *

(d) * * *

(2) For Method 5 or 5B of appendix A–3 of this part, Method 17 of appendix A–6 of this part may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A–3 of this part may be used with Method 17 of appendix A–6 of this part only if it is used after wet FGD systems. Method 17 of appendix A–6 of this part shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

* * * * *

Subpart Da—[Amended]

■ 7. Section 60.40Da is amended by revising paragraphs (a) and (b), and adding paragraph (e) to read as follows:

§ 60.40Da Applicability and designation of affected facility.

(a) Except as specified in paragraph (e) of this section, the affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr)) heat input of fossil fuel (either alone or in combination with any other fuel); and

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

(b) An IGCC electric utility steam generating unit (both the stationary combustion turbine and any associated duct burners) is subject to this part and is not subject to subpart GG or KKKK of this part if both of the conditions specified in paragraphs (b)(1) and (2) of this section are met.

(1) The IGCC electric utility steam generating unit is capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) The IGCC electric utility steam generating unit commenced construction, modification, or reconstruction after February 28, 2005.

* * * * *

(e) Applicability of the requirement of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as specified in paragraphs (e)(1) and (2) of this section.

(1) Heat recovery steam generators used with duct burners and associated with an electric utility combined cycle gas turbine that are capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel are subject to this subpart except in cases when the heat recovery steam generator meets the applicability requirements and is subject to subpart KKKK of this part.

(2) For heat recovery steam generators use with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (i.e. duct burners) are subject to the standards under this subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKK, as applicable, of this part).

■ 8. Section 60.41Da is amended by revising the definitions of “Gross output,” “Integrated gasification combined cycle electric utility steam generating unit or IGCC electric utility steam generating unit,” “Natural gas,” and “Petroleum” to read as follows:

§ 60.41Da Definitions.

* * * * *

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit’s turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process).

* * * * *

Integrated gasification combined cycle electric utility steam generating

unit or IGCC electric utility steam generating unit means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. No solid fuel is directly burned in the unit during operation.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth’s surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

* * * * *

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, and residual oil.

* * * * *

■ 9. Section 60.42Da is amended by revising paragraph (b) to read as follows:

§ 60.42Da Standard for particulate matter (PM).

* * * * *

(b) On and after the date the initial PM performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart are exempt from the opacity standard specified in this paragraph b.

* * * * *

■ 10. Section 60.48Da is amended to read as follows:

- a. By revising paragraph (g)(3);
- b. By revising the first sentence of paragraph (j)(2);
- c. By revising paragraph (n);
- d. By revising paragraph (o) introductory text;

- e. By revising paragraph (o)(1);
- f. By revising paragraph (o)(2)(ii);
- g. By revising the last sentence of paragraph (o)(2)(iii);
- h. By revising paragraphs (o)(2)(iv) and (o)(2)(vi);
- i. By revising paragraphs (o)(3)(i) and (o)(3)(ii);
- j. By revising the first sentence of paragraph (o)(3)(iii);
- k. By revising the last sentence of paragraph (o)(3)(v);
- l. By revising paragraph (o)(4)(i)(E);
- m. By revising the first sentence of paragraph (o)(4)(ii);
- n. By revising paragraphs (o)(4)(ii)(F), (o)(4)(v) and (o)(4)(5);
- o. By revising paragraph (p) introductory text and (p)(2); and
- p. By adding paragraph (q).

§ 60.48Da Compliance provisions.

* * * * *

(g) * * *

(3) Compliance with applicable daily average PM emission limitations is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Averages are only calculated for boiler operating days that have valid data for at least 18 hours of unit operation during which the standard applies. Instead, all of the valid hourly emission rates of the operating day(s) not meeting the minimum 18 hours valid data daily average requirement are averaged with all of the valid hourly emission rates of the next boiler operating day with 18 hours or more of valid PM CEMS data to determine compliance.

* * * * *

(j) * * *

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the CEMS specified under § 60.49Da for measuring NO_x and oxygen (O₂) (or carbon dioxide (CO₂)) and meet the requirements of § 60.49Da. * * *

* * * * *

(n) *Compliance provisions for sources subject to § 60.42Da(c)(1)*. The owner or operator of an affected facility subject to § 60.42Da(c)(1) shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of § 60.49Da(t)), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)). Compliance with the

emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

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

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in § 60.42Da(c)(2) or (d) by the applicable date specified in § 60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months following the date the previous performance test was required to be conducted. You must conduct each performance test according to the requirements in § 60.8 using the test methods and procedures in § 60.50Da. The owner or operator of an affected facility that has not operated for 60 consecutive calendar days prior to the date that the subsequent performance test would have been required had the unit been operating is not required to perform the subsequent performance test until 30 calendar days after the next boiler operating day. Requests for additional 30 day extensions shall be granted by the relevant air division or office director of the appropriate Regional Office of the U.S. EPA.

(2) * * *

(ii) You must comply with the quality assurance requirements in paragraphs (o)(2)(ii)(A) through (E) of this section.

* * * * *

(iii) * * * If your opacity baseline level is less than 5.0 percent, then the opacity baseline level is set at 5.0 percent.

(iv) You must evaluate the preceding 24-hour average opacity level measured by the COMS each boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the measured 24-hour average opacity emission level is greater than the baseline opacity level determined in paragraph (o)(2)(iii) of this section, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high opacity incident and take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the measured 24-hour average opacity to a level below the baseline opacity level.

In cases when a wet scrubber is used in combination with another PM control device that serves as the primary PM control device, the wet scrubber must be maintained and operated.

* * * * *

(vi) If the measured 24-hour average opacity for your affected facility remains at a level greater than the opacity baseline level after 7 boiler operating days, then you must conduct a new PM performance test according to paragraph (o)(1) of this section and establish a new opacity baseline value according to paragraph (o)(2) of this section. This new performance test must be conducted within 60 days of the date that the measured 24-hour average opacity was first determined to exceed the baseline opacity level unless a waiver is granted by the permitting authority.

(3) * * *

(i) You must calibrate the ESP predictive model with each PM control device used to comply with the applicable PM emissions limit in § 60.42Da(c)(2) or (d) operating under normal conditions. In cases when a wet scrubber is used in combination with an ESP to comply with the PM emissions limit, the wet scrubber must be maintained and operated.

(ii) You must develop a site-specific monitoring plan that includes a description of the ESP predictive model used, the model input parameters, and the procedures and criteria for establishing monitoring parameter baseline levels indicative of compliance with the PM emissions limit. You must submit the site-specific monitoring plan for approval by the permitting authority. For reference purposes in preparing the monitoring plan, see the OAQPS "Compliance Assurance Monitoring (CAM) Protocol for an Electrostatic Precipitator (ESP) Controlling Particulate Matter (PM) Emissions from a Coal-Fired Boiler." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality Planning and Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Continuous Emission Monitoring.

(iii) You must run the ESP predictive model using the applicable input data each boiler operating day and evaluate the model output for the preceding boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. * * *

* * * * *

(v) * * * This new performance test must be conducted within 60 calendar days of the date that the model parameter was first determined to exceed its baseline level unless a waiver is granted by the permitting authority.

(4) * * *

(i) * * *

(E) Following initial adjustment, you must not adjust the averaging period, alarm set point, or alarm delay time without approval from the permitting authority except as provided in paragraph (d)(1)(vi) of this section.

* * * * *

(ii) You must develop and submit to the permitting authority for approval a site-specific monitoring plan for each bag leak detection system. * * *

* * * * *

(F) Corrective action procedures as specified in paragraph (o)(4)(iii) of this section. In approving the site-specific monitoring plan, the permitting authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

* * * * *

(v) If after any period composed of 30 boiler operating days during which the alarm rate exceeds 5 percent of the process operating time (excluding control device or process startup, shutdown, and malfunction), then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 calendar days of the date that the alarm rate was first determined to exceed 5 percent limit unless a waiver is granted by the permitting authority.

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

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner

or operator may elect to install, evaluate, maintain, and operate a CEMS measuring PM emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

* * * * *

(2) Each CEMS shall be installed, evaluated, operated, and maintained according to the requirements in § 60.49Da(v).

* * * * *

(q) *Compliance provisions for sources subject to § 60.42Da(b).* An owner or operator of an affected facility subject to the opacity standard in § 60.42Da(b) shall monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the requirements in § 60.49Da(a), as applicable to the affected facility.

■ 11. Section 60.49Da is amended to read as follows:

- a. By revising paragraph (a);
- b. By revising paragraphs (b)(4) introductory text and (b)(4)(iii);
- c. By revising paragraph (d);
- d. By revising paragraph (i)(3);
- e. By revising paragraph (k) introductory text;
- f. By revising paragraph (t);
- g. By revising paragraph (u);
- h. By revising paragraphs (v) introductory text and (v)(2), and adding paragraph (v)(4); and
- j. By adding paragraph (w) introductory text;
- k. By revising paragraphs (w)(1) and (w)(2).

§ 60.49Da Emission monitoring.

(a) An owner or operator of an affected facility subject to the opacity standard in § 60.42Da(b) shall monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the applicable requirements in paragraphs (a)(1) through (3) of this section.

(1) Except as provided for in paragraph (a)(2) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a COMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO₂ control system), alternate parameters indicative of the PM control system's performance and/or good

combustion are monitored (subject to the approval of the Administrator).

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), or (iii) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

(i) The affected facility uses a fabric filter (baghouse) to meet the standards in § 60.42Da and a bag leak detection system is installed and operated according to the requirements in paragraphs § 60.48Da(o)(4)(i) through (v);

(ii) The affected facility burns only gaseous or liquid fuels (excluding residual oil) with potential SO₂ emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO₂ or PM; or

(iii) The affected facility meets all of the conditions specified in paragraphs (a)(2)(iii)(A) through (C) of this section.

(A) No post-combustion technology (except a wet scrubber) is used for reducing PM, SO₂, or carbon monoxide (CO) emissions;

(B) Only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur are burned; and

(C) Emissions of CO discharged to the atmosphere are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis as demonstrated by the use of a CEMS measuring CO emissions according to the procedures specified in paragraph (u) of this section.

(3) The owner or operators of an affected facility that meets the conditions in paragraph (a)(2) of this section may, as an alternative to COMS, elect to monitor visible emissions using the applicable procedures specified in paragraphs (a)(3)(i) through (iv) of this section.

(i) The owner or operator shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11. If during the initial 60 minutes of the observation all the 6-minute averages are less than 10 percent and all the individual 15-second observations are less than or equal to 20 percent, then the observation period may be reduced from 3 hours to 60 minutes.

(ii) Except as provided in paragraph (a)(3)(iii) or (iv) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a)(3)(i) of this section according to the applicable

schedule in paragraphs (a)(3)(ii)(A) through (a)(3)(ii)(D) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted; or

(D) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 30 calendar days from the date that the most recent performance test was conducted.

(iii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(3)(iii)(A) and (B) of this section.

(A) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.*, 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.*, 90 seconds per 30 minute period) the owner or operator shall either document and adjust the

operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.*, 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a)(3)(i) of this section within 30 calendar days according to the requirements in § 60.50Da(b)(3).

(B) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(iv) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(3)(iii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) * * *

(4) If the owner or operator has installed and certified a SO₂ CEMS according to the requirements of § 75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used to meet the requirements of this section, provided that:

* * * * *

(iii) The reporting requirements of § 60.51Da are met. The SO₂ and, if required, CO₂ (or O₂) data reported to meet the requirements of § 60.51Da shall not include substitute data values

derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO₂ data have been bias adjusted according to the procedures of part 75 of this chapter.

* * * * *

(d) The owner or operator of an affected facility not complying with an output based limit shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O₂ or carbon dioxide (CO₂) content of the flue gases at each location where SO₂ or NO_x emissions are monitored. For affected facilities subject to a lb/MMBtu SO₂ emission limit under § 60.43Da, if the owner or operator has installed and certified a CO₂ or O₂ monitoring system according to § 75.20(c) of this chapter and appendix A to part 75 of this chapter and the monitoring system continues to meet the applicable quality-assurance provisions of § 75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used together with the part 75 SO₂ concentration monitoring system described in paragraph (b) of this section, to determine the SO₂ emission rate in lb/MMBtu. SO₂ data used to meet the requirements of § 60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

* * * * *

(i) * * *

(3) For affected facilities burning only fossil fuel, the span value for a COMS is between 60 and 80 percent. Span values for a CEMS measuring NO_x shall be determined using one of the following procedures:

* * * * *

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under §§ 60.42Da(c), 60.43Da(i), 60.43Da(j), 60.44Da(d)(1), and 60.44Da(e).

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under § 60.42Da(c)(1) shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected facility demonstrating compliance with the input-based emission limitation in § 60.42Da(a)(1) or

§ 60.42Da(c)(2) may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) The owner or operator of an affected facility using a CEMS measuring CO emissions to meet requirements of this subpart shall meet the requirements specified in paragraphs (u)(1) through (4) of this section.

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (u)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly useful energy output from the affected facility. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 1.4 lb/MWh, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 1.4 lb/MWh or less.

(4) You must record the CO measurements and calculations performed according to paragraph (u)(3)

of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 1.4 lb/MWh, and the date, time, and description of the corrective action.

(v) The owner or operator of an affected facility using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (v)(1) through (v)(4) of this section.

* * * * *

(2) During each PM correlation testing run of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O₂ (or CO₂) data shall be collected concurrently (or within a 30- to 60-minute period) by both the CEMS and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change has been published in the **Federal Register**, whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For O₂ (or CO₂), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

* * * * *

(4) After July 1, 2011, within 90 days after the date of completing each performance evaluation required by paragraph (v) of this section, the owner or operator of the affected facility must either submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at <http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main> or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243-01; RTP, NC 27711.

(w) The owner or operator using a SO₂, NO_x, CO₂, and O₂ CEMS to meet the requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (w)(1) through (w)(5) of this section.

(1) Except as provided for under paragraphs (w)(2), (w)(3), and (w)(4) of this section, each SO₂, NO_x, CO₂, and O₂ CEMS required under paragraphs (b) through (d) of this section shall be installed, certified, and operated in

accordance with the applicable procedures in Performance Specification 2 or 3 in appendix B to this part or according to the procedures in appendices A and B to part 75 of this chapter. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to this part, and a data assessment report (DAR), prepared according to section 7 of Procedure 1 in appendix F to this part, shall be submitted with each compliance report required under § 60.51Da.

(2) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to implement the following alternative data accuracy assessment procedures. For all required CO₂ and O₂ CEMS and for SO₂ and NO_x CEMS with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F of this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to SO₂ and NO_x span values less than 100 ppm;

* * * * *

■ 12. Section 60.50Da is amended by revising paragraphs (e)(1) and (f) to read as follows:

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(e) * * *

(1) For Method 5 or 5B of appendix A-3 of this part, Method 17 of appendix A-6 of this part may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after wet FGD systems. Method 17 of appendix A-6 of this part shall not be used after wet FGD systems if the

effluent is saturated or laden with water droplets.

* * * * *

(f) Electric utility combined cycle gas turbines that are not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas are performance tested for PM, SO₂, and NO_x using the procedures of Method 19 of appendix A-7 of this part. The SO₂ and NO_x emission rates calculations from the gas turbine used in Method 19 of appendix A-7 of this part are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

* * * * *

■ 13. Section 60.51Da is amended by revising paragraphs (b)(2) and (b)(3) to read as follows:

§ 60.51Da Reporting requirements.

* * * * *

(b) * * *

(2) The average SO₂ and NO_x emission rates (ng/J, lb/MMBtu, or lb/MWh) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) For owners or operators of affected facilities complying with the percent reduction requirement, percent reduction of the potential combustion concentration of SO₂ for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

* * * * *

■ 14. Section 60.52Da is revised to read as follows:

§ 60.52Da Recordkeeping requirements.

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

(b) The owner or operator of an affected facility subject to the opacity limits in § 60.42Da(b) that elects to monitor emissions according to the requirements in § 60.49Da(a)(3) shall maintain records according to the requirements specified in paragraphs

(b)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (b)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods; (ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (b)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

Subpart Db—[Amended]

■ 15. Section 60.40b is amended by revising the first sentence of paragraph (i) to read as follows:

§ 60.40b Applicability and delegation of authority.

(i) Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart.

■ 16. Section 60.41b is amended by revising the definitions of “Coal,” “Distillate oil,” “Gaseous fuel,” “Gross output,” “Natural gas,” “Potential sulfur dioxide emission rate,” “Steam generating unit,” and “Very low sulfur oil” to read as follows:

§ 60.41b Definitions.

* * * * *

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

* * * * *

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17).

* * * * *

Gaseous fuel means any fuel that is a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process).

* * * * *

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth’s surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic

meter (910 and 1,150 Btu per dry standard cubic foot).

* * * * *

Potential sulfur dioxide emission rate means the theoretical SO₂ emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO₂ emissions (ng/J or lb/MMBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion emission control systems.

* * * * *

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

* * * * *

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO₂ emission control, has a SO₂ emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO₂ emission control, has a SO₂ emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO₂ emission control, has a SO₂ emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input.

■ 17. Section 60.42b is amended to read as follows:

- a. By revising paragraph (a);
- b. By revising paragraph (b);
- c. By revising paragraph (c);
- d. By revising paragraph (d) introductory text; and
- e. By revising paragraphs (k)(1), (k)(2), and (k)(3).

§ 60.42b Standard for sulfur dioxide (SO₂).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

Where:

E_s = SO₂ emission limit, in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (or 1.2 lb/MMBtu);

K_b = 340 ng/J (or 0.80 lb/MMBtu);

H_a = Heat input from the combustion of coal, in J (MMBtu); and

H_b = Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO₂ emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable. For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion

of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(c) On and after the date on which the performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO₂ emissions, shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 50 percent of the potential SO₂ emission rate (50 percent reduction) and that contain SO₂ in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:

E_s = SO₂ emission limit, in ng/J or lb/MMBtu heat input;

K_c = 260 ng/J (or 0.60 lb/MMBtu);

K_d = 170 ng/J (or 0.40 lb/MMBtu);

H_c = Heat input from the combustion of coal, in J (MMBtu); and

H_d = Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section. For facilities complying with paragraphs (d)(1), (2), or (3) of this section, only the

heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

* * * * *

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO₂ emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO₂ emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO₂ emissions limit in paragraph (k)(1) of this section.

(3) Units that are located in a noncontinental area and that combust coal, oil, or natural gas shall not discharge any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil or natural gas.

* * * * *

■ 18. Section 60.43b is amended to read as follows:

■ a. By revising paragraph (f);

■ b. By revising paragraph (g); and

■ c. By revising paragraphs (h)(1) and (h)(5) and adding paragraph (h)(6).

§ 60.43b Standard for particulate matter (PM).

* * * * *

(f) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

* * * * *

(5) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO₂ or PM emissions is not subject to the PM limits in (h)(1) of this section.

(6) On and after the date on which the initial performance test is completed or

is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.5 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO₂ or PM emissions is not subject to the PM limits in (h)(1) of this section.

■ 19. Section 60.44b is amended by revising paragraph (l)(1) to read as follows:

§ 60.44b Standard for nitrogen oxides (NO_x).

* * * * *

(l) * * *

(1) If the affected facility combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels: A limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

* * * * *

■ 20. Section 60.45b is amended to read as follows:

- a. By revising paragraph (a);
- b. By revising paragraphs (c)(2)(i), (c)(4) introductory text, and (c)(5);
- c. By revising paragraph (d) introductory text;
- d. By revising paragraph (j); and
- e. By revising paragraph (k).

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO₂ emission standards in § 60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO₂ control system maintenance.

* * * * *

(c) * * *

(2) * * *

(i) The procedures in Method 19 of appendix A-7 of this part are used to determine the hourly SO₂ emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are

obtained from the CEMS of § 60.47b(a) or (b).

* * * * *

(4) The owner or operator of an affected facility subject to paragraph (c)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that X_k= 1.0. Owners or operators of affected facilities who assume X_k = 1.0 shall:

* * * * *

(5) The owner or operator of an affected facility that qualifies under the provisions of § 60.42b(d) does not have to measure parameters E_w or X_k in paragraph (c)(3) of this section if the owner or operator of the affected facility elects to measure SO₂ emission rates of the coal or oil following the fuel sampling and analysis procedures in Method 19 of appendix A-7 of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, natural gas, or a mixture of these fuels, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

* * * * *

(j) The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO₂ standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in § 60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §§ 60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures in § 60.49b(r).

■ 21. Section 60.46b is amended to read as follows:

- a. By revising paragraphs (d)(1) and (d)(2)(ii);
- b. By revising paragraphs (e)(2) and (e)(4);
- c. By revising paragraph (g);
- d. By revising paragraph (i); and
- e. By revising paragraphs (j) introductory text and (j)(11) and adding paragraph (j)(14).

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

* * * * *

(d) * * *

(1) Method 3A or 3B of appendix A-2 of this part is used for gas analysis when applying Method 5 of appendix

A-3 of this part or Method 17 of appendix A-6 of this part.

(2) * * *

(ii) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

* * * * *

(e) * * *

(2) Following the date on which the initial performance test is completed or is required to be completed in § 60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal (except as specified under § 60.46b(e)(4)) or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_x emission standards in § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

* * * * *

(4) Following the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_x standards in § 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_x emissions data collected pursuant to § 60.48b(g)(1) or § 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_x emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

* * * * *

(g) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method or the heat input method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see § 60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of § 60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of § 60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

* * * * *

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the PM limit in paragraphs § 60.43b(a)(4) or § 60.43b(h)(5) shall follow the applicable procedures in § 60.49b(r).

(j) In place of PM testing with Method 5 or 5B of appendix A-3 of this part, or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(14) of this section.

* * * * *

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O₂ (or CO₂) data shall be collected concurrently (or within a 30-to 60-

minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change has been published in the **Federal Register**, whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For O₂ (or CO₂), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

* * * * *

(14) After July 1, 2011, within 90 days after completing a correlation testing run, the owner or operator of an affected facility shall either successfully enter the test data into EPA's WebFIRE data base located at <http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main> or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243-01; RTP, NC 27711.

* * * * *

■ 22. Section 60.47b is amended by revising the first sentence of paragraph (a) introductory text and the first sentence of paragraph (e)(4)(i) to read as follows:

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO₂ standards in § 60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO₂ concentrations and either O₂ or CO₂ concentrations and shall record the output of the systems.

* * *

* * * * *

(e) * * *

(4) * * *

(i) For all required CO₂ and O₂ monitors and for SO₂ and NO_x monitors with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part. * * *

* * * * *

■ 23. Section 60.48b is amended to read as follows:

- a. By revising paragraph (a);
- b. By revising paragraph (e)(1);
- c. By revising paragraph (g) introductory text;
- d. By revising paragraph (h);
- e. By revising paragraphs (j) introductory text, the last sentence of (j)(4) introductory text, (j)(4)(i)(C), (j)(5) and adding (j)(6); and
- f. By revising the first sentence of paragraph (k).

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), or (5) of this section who elects not to install a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. If during the initial 60 minutes of observation all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent, the observation period may be reduced from 3 hours to 60 minutes.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the

most recent performance test was conducted;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 30 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.*, 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.*, 90 seconds per 30 minute period) the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.*, 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 30 calendar days according to the requirements in § 60.46d(d)(7).

(ii) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

* * * * *

(e) * * *

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a COMS shall be between 60 and 80 percent.

* * * * *

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

* * * * *

(h) The owner or operator of a duct burner, as described in § 60.41b, that is subject to the NO_x standards in § 60.44b(a)(4), § 60.44b(e), or § 60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions.

* * * * *

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), or (6) of this section is not required to install or operate a COMS if:

* * * * *

(4) * * * Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section; or

(j) * * *

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

* * * * *

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most recent requirements in section § 60.48Da of this part; or

(6) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.46b(j).

■ 24. Section 60.49b is amended to read as follows:

- a. By revising paragraphs (c) introductory text and (c)(3);
- b. By revising paragraph (d);
- c. By revising paragraph (f);
- d. By revising paragraph (h)(1) and (h)(2)(i);
- e. By revising paragraph (k)(2);
- f. By revising paragraph (m) introductory text; and
- g. By revising paragraph (r)(1).

§ 60.49b Reporting and recordkeeping requirements.

* * * * *

(c) The owner or operator of each affected facility subject to the NO_x standard in § 60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of § 60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in § 60.48b(g)(2) and the records to be maintained in § 60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360

days of the initial startup of the affected facility or by November 30, 2009, whichever date comes later. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

* * * * *

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under § 60.49b(g).

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(2) As an alternative to meeting the requirements of paragraph (d)(1) of this section, the owner or operator of an affected facility that is subject to a federally enforceable permit restricting fuel use to a single fuel such that the facility is not required to continuously monitor any emissions (excluding opacity) or parameters indicative of emissions may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

* * * * *

(f) For an affected facility subject to the opacity standard in § 60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in § 60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this

section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

* * * * *

(h) * * *

(1) Any affected facility subject to the opacity standards in § 60.43b(f) or to the operating parameter monitoring requirements in § 60.13(i)(1).

(2) * * *

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

* * * * *

(k) * * *

(2) Each 30-day average SO₂ emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO₂ control system covered in paragraph 60.45b(a), the report shall identify the days on which the

maintenance was performed and a description of the maintenance;

* * * * *

(m) For each affected facility subject to the SO₂ standards in § 60.42(b) for which the minimum amount of data required in § 60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

* * * * *

(r) * * *

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

Subpart Dc—[Amended]

- 25. Section 60.40c is amended to read as follows:
 - a. By revising paragraph (a);
 - b. By revising the first sentence of paragraph (e);
 - c. By revising paragraph (f); and
 - d. By revising paragraph (g).

Where:

E_s = SO₂ emission limit, expressed in ng/J or lb/MMBtu heat input;
 K_a = 520 ng/J (1.2 lb/MMBtu);
 K_b = 260 ng/J (0.60 lb/MMBtu);
 K_c = 215 ng/J (0.50 lb/MMBtu);
 H_a = Heat input from the combustion of coal, except coal combusted in an affected

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

* * * * *

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart.

* * *

(f) Any facility covered by subpart AAAA of this part is not subject by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject by this subpart.

■ 26. Section 60.41c is amended by revising the definitions of “Coal,” “Distillate oil,” “Natural gas,” and “Steam generating unit” to read as follows:

§ 60.41c Definitions.

* * * * *

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

* * * * *

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];
 H_b = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17) or diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17).

* * * * *

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth’s surface, of which the principal constituent is methane; or

(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

* * * * *

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

* * * * *

■ 27. Section 60.42c is amended by revising paragraphs (e)(2) and (j) to read as follows:

§ 60.42c Standard for sulfur dioxide (SO₂).

* * * * *

(e) * * *

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

H_c = Heat input from the combustion of oil, in J (MMBtu).

* * * * *

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the

combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

■ 28. Section 60.43c is amended by revising paragraph (c) to read as follows:

§ 60.43c Standard for particulate matter (PM).

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph.

■ 29. Section 60.44c is amended by revising paragraph (h) to read as follows:

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(h) For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO₂ standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in § 60.48c(f), as applicable.

■ 30. Section 60.45c is amended to read as follows:

- a. By revising paragraphs (a)(2) and (a)(8);
- b. By revising paragraphs (c) introductory text, (c)(7) introductory text, (c)(8), (c)(9), and (c)(11), and by adding paragraph (c)(14).

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) * * *
(2) Method 3A or 3B of appendix A–2 of this part shall be used for gas

analysis when applying Method 5 or 5B of appendix A–3 of this part or 17 of appendix A–6 of this part.

(8) Method 9 of appendix A–4 of this part shall be used for determining the opacity of stack emissions.

(c) In place of PM testing with Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O₂ (or CO₂) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change

has been published in the **Federal Register**, whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For O₂ (or CO₂), Method 3A or 3B of appendix A–2 of this part, as applicable shall be used.

(14) After July 1, 2011, within 90 days after the date of completing each performance evaluation required by paragraph (c)(11) of this section, the owner or operator of the affected facility must either submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at <http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main> or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243–01; RTP, NC 27711.

■ 31. Section 60.47c is amended to read as follows:

- a. By revising paragraph (a);
- b. By revising paragraph (b);
- c. By revising paragraph (c);
- d. By revising paragraph (d);
- e. By revising paragraphs (e) introductory text and (e)(1)(iii);
- f. By revising paragraph (f); and
- g. By adding paragraph (g).

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), (f), and (g) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) and that is not required to install a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to install a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. If during the initial 60 minutes of observation all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent, the observation period may be reduced from 3 hours to 60 minutes.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 30 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.*, 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation,

immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.*, 90 seconds per 30 minute period) the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.*, 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 30 calendar days according to the requirements in § 60.45c(a)(8).

(ii) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur

dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO₂ or PM emissions and that are subject to an opacity standard in § 60.43c(c) are not required to operate a COMS if they follow the applicable procedures in § 60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.45c(c). The CEMS specified in paragraph § 60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO₂, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) * * *

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

* * * * *

(f) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most recent requirements in section § 60.48Da of this part is not required to operate a COMS.

(g) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur and operates according to a written site-specific monitoring plan

approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

■ 32. Section 60.48c is amended to read as follows:

- a. By revising paragraph (c);
- b. By revising paragraph (e)(11); and
- c. By revising paragraphs (f)(1)(iii) and (f)(4)(ii).

§ 60.48c Reporting and recordkeeping requirements.

* * * * *

(c) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the

information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or

operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

* * * * *

(e) * * *

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) * * *

(1) * * *

(iii) The sulfur content or maximum sulfur content of the oil.

* * * * *

(4) * * *

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

* * * * *

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