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Part II

Environmental Protection Agency

40 CFR Part 60

**Standards of Performance for Electric
Utility Steam Generating Units, Industrial-
Commercial-Institutional Steam
Generating Units, and Small Industrial-
Commercial-Institutional Steam
Generating Units; Final Rule**

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2005-0031; FRL-8033-3]

RIN 2060-AM80

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; amendments.

SUMMARY: Pursuant to section 111(b)(1)(B) of the Clean Air Act (CAA), EPA has reviewed the emission standards for nitrogen oxides (NO_x), sulfur dioxide (SO₂), and particulate matter (PM) contained in the new source performance standards (NSPS) for electric utility steam generating units and industrial-commercial-institutional steam generating units. EPA proposed amendments to 40 CFR part 60, subparts Da, Db, and Dc, on February 28, 2005. This action reflects EPA's responses to issues raised by commenters, and promulgates the amended standards of performance.

The final rule amendments revise the existing standards for PM emissions by

reducing the numerical emission limits for both utility and industrial-commercial-institutional steam generating units and revise the existing standards for NO_x emissions by reducing the numerical emission limits for utility steam generating units. The amendments also revise the standards for SO₂ emissions for both electric utility and industrial-commercial-institutional steam generating units. The numerical standard for electric utility steam generating units has been reduced, and the maximum percent reduction requirement has been increased. A numerical standard has been added for units presently subject to the NSPS and new industrial-commercial-institutional steam generating units, and the maximum percent reduction requirement for new units has been increased. Both utility and industrial steam generating units can either meet a numerical limit or demonstrate a percent reduction.

Several technical clarifications and compliance alternatives have been added to the existing provisions of the current rules.

DATES: The final rule amendments are effective on February 27, 2006.

ADDRESSES: *Docket:* EPA has established a docket for this action under Docket ID No. EPA-HQ-OAR-2005-0031. All documents in the docket are listed on the Internet at <http://www.regulations.gov>. Although listed in the index, some information is not publicly available, e.g., CBI 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 Air and Radiation Docket, Docket ID No. EPA-HQ-2004-0490, EPA/DC, EPA West, Room B102, 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 and Radiation Docket Center is (202) 566-1742.

FOR FURTHER INFORMATION CONTACT: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (C439-01), U.S. EPA, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-4003; e-mail fellner.christian@epa.gov.

SUPPLEMENTARY INFORMATION: *Regulated Entities.* Categories and entities potentially regulated by the final rule amendments are new, reconstructed, and modified electric utility steam generating units and new, reconstructed, and modified industrial-commercial-institutional steam generating units. The final rule amendments will affect the following categories of sources:

Category	NAICS code	SIC code	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 boiler as defined in 60.40b or 60.40c.	921150	Fossil fuel-fired electric steam generating units in Indian Country.
	211	13	Extractors of crude petroleum and natural gas.
	321	24	Manufacturers of lumber and wood products.
	322	26	Pulp and paper mills.
	325	28	Chemical manufacturers.
	324	29	Petroleum refiners and manufacturers of coal products.
	316, 326, 339	30	Manufacturers of rubber and miscellaneous plastic products.
	331	33	Steel works, blast furnaces.
	332	34	Electroplating, plating, polishing, anodizing, and coloring.
	336	37	Manufacturers of motor vehicle parts and accessories.
	221	49	Electric, gas, and sanitary services.
	622	80	Health services.
	611	82	Educational services.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be subject to the final rule amendments. To determine whether your facility may be

subject to the final rule amendments, you should examine the applicability criteria in 40 CFR part 60, sections 60.40a, 60.40b, or 60.40c. If you have any questions regarding the

applicability of the final rule amendments to a particular entity, contact the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

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

Judicial Review. Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of the final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia by April 28, 2006. Under section 307(d)(7)(B) of the CAA, only an objection to the final rule 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 today's final action may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

Section 307(d)(7)(B) of the CAA further provides that "only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for EPA to convene a proceeding for reconsideration, "if the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to EPA should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460, with a copy to both the person(s) listed in the **FOR FURTHER INFORMATION CONTACT** section, and the Director of the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave, NW., Washington, DC 20004.

Outline. The following outline is provided to aid in locating information in this preamble.

I. Summary of the Final Rule.

- A. What are the requirements for new electric utility steam generating units (40 CFR part 60, subpart Da)?

- B. What are the requirements for industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db)?
 - C. What are the requirements for small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc)?
- #### II. Background Information
- A. What is the statutory authority for the final rule?
 - B. What is the regulatory authority for the final rule?
- #### III. Responses to Public Comments
- A. Electric Utility Steam Generating Units (40 CFR Part 60, Subpart Da)
 - B. Industrial-Commercial-Institutional and Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subparts Db and Dc)
- #### IV. Impacts of the Final Rules
- A. What are the impacts for electric utility steam generating units (40 CFR part 60, subpart Da)?
 - B. What are the impacts for industrial-commercial-institutional boilers (40 CFR part 60, subparts Db and Dc)?
 - C. What are the economic impacts?
 - D. What are the social costs and benefits?
- #### V. Statutory and Executive Order Reviews
- A. Executive Order 12866: Regulatory Planning and Review
 - B. Paperwork Reduction Act
 - C. Regulatory Flexibility Act
 - D. Unfunded Mandates Reform Act
 - E. Executive Order 13132: Federalism
 - F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
 - G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks
 - H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution or Use
 - I. National Technology Transfer Advancement Act
 - J. Congressional Review Act

I. Summary of Final Rule

The final rule amends the emission limits for SO₂, NO_x, and PM for subpart Da, 40 CFR part 60 (electric utility steam generating units) the SO₂ and PM emission limits for subpart Db, 40 CFR part 60 (industrial-commercial-institutional steam generating units), and the SO₂ and PM emission limits for subpart Dc, 40 CFR part 60 (small industrial-commercial-institutional steam generating units). With one exception, only those units that begin construction, modification, or reconstruction after February 28, 2005, will be affected by the final rule. The exception is that the SO₂ standard for industrial-commercial-institutional units presently subject to the NSPS has been amended to reflect the difficulty of units burning fuels with inherently low sulfur emissions from consistently achieving 90 percent reduction. Compliance with the emission limits of the final rule will be determined using

similar testing, monitoring, and other compliance provisions set forth in the existing standards.

In addition to the emissions limits contained in the final rule, we also are including several technical clarifications and corrections to existing provisions of the existing amendments, as explained below. We included language to clarify the applicability of subparts Da, Db, and Dc of 40 CFR part 60 to combined cycle power plants. Heat recovery steam generators that are associated with combined cycle and combined heat and power combustion turbines burning less than 75 percent (by heat input) synthetic-coal gas are not subject to subparts Da, Db, or Dc, 40 CFR part 60, if the unit meets the applicability requirements of subpart KKKK, 40 CFR part 60 (Standards of Performance for Stationary Combustion Turbines). Subpart Da of 40 CFR part 60 will apply to combined cycle and combined heat and power combustion turbines and the associated heat recovery units that burn 75 percent or more (by heat input) synthetic-coal gas (e.g., integrated coal gasification combine cycle power plants) and that meet the applicability criteria of the final rule amendments, respectively.

We also made amendments to the definitions for boiler operating day, cogeneration, coal, gross output, and petroleum. The purpose of the final rule amendments is to clarify definitions across the three subparts and to incorporate the most current applicable American Society for Testing and Materials (ASTM) testing method references. Also, we clarified the definition of an "electric utility steam generating unit" as applied to cogeneration units.

A. What are the requirements for new electric utility steam generating units (40 CFR part 60, subpart Da)?

The PM emission limit for new and reconstructed electric utility steam generating units is 6.4 nanograms per joule (ng/J) (0.015 pound per million British thermal units (lb/MMBtu)) heat input or 99.9 percent reduction regardless of the type of fuel burned. The PM emission limit for modified electric utility steam generating units is 6.4 ng/J (0.015 lb/MMBtu) heat input or 99.8 percent reduction regardless of the type of fuel burned. Compliance with this emission limit can be determined using similar testing, monitoring, and other compliance provisions for PM standards set forth in the existing rule. While not required, PM CEMS may be used as an alternative method to demonstrate continuous compliance

and as an alternative to opacity and parameter monitoring requirements.

The SO₂ emission limit for new electric utility steam generating units is 180 ng/J (1.4 pound per megawatt hour (lb/MWh)) gross energy output or 95 percent reduction regardless of the type of fuel burned with one exception. The SO₂ emission limit for new electric utility steam generating units that burn over 75 percent coal refuse (by heat input) is 180 ng/J (1.4 lb/MWh) gross energy output or 94 percent reduction. The SO₂ emission limit for reconstructed and modified electric utility steam generating units burning any fuel except over 75 percent coal refuse (by heat input) is 65 ng/J (0.15 lb/MMBtu) heat input or 95 percent reduction and 65 ng/J (0.15 lb/MMBtu) heat input or 90 percent reduction, respectively. The SO₂ emission limit for reconstructed and modified electric utility steam generating units burning over 75 percent coal refuse (by heat input) is 65 ng/J (0.15 lb/MMBtu) or 94 percent reduction and 65 ng/J (0.15 lb/MMBtu) or 90 percent reduction, respectively. Compliance with the SO₂ emission limit is determined on a 30-day rolling average basis using a CEMS to measure SO₂ emissions as discharged to the atmosphere and following the compliance provisions in the existing rule for the output-based NO_x standards applicable to new sources that were built after July 9, 1997.

The NO_x emission limit for new electric utility steam generating units is 130 ng/J (1.0 lb NO_x/MWh) gross energy output regardless of the type of fuel burned in the unit. Compliance with this emission limit is determined on a 30-day rolling average basis using similar testing, monitoring, and other compliance provisions in the existing rule for the output-based NO_x standards applicable to new sources that were built after July 9, 1997. The NO_x limit for reconstructed and modified electric utility steam generating units is 47 ng/J (0.11 lb/MMBtu) heat input and 65 ng/J (0.15 lb/MMBtu) heat input, respectively.

B. What are the requirements for industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db)?

The PM emission limit for new and reconstructed industrial-commercial-institutional steam generating units is 13 ng/J (0.03 lb/MMBtu) for units that burn coal, oil, gas, wood, or a mixture of these fuels with other fuels. The PM emission limit for modified industrial-commercial-institutional steam generating units is 13 ng/J (0.03 lb/MMBtu) heat input or 99.8 percent

reduction [with a maximum emission limit of 22 ng/J (0.051 lb/MMBtu) heat input] for units that burn coal, oil, gas, wood, or a mixture of these fuels with other fuels with two exceptions. The standard for modified wood-fired units with a maximum heat input less than or equal to 250 MMBtu/h is 43 ng/J (0.10 lb/MMBtu) heat input and 37 ng/J (0.085 lb/MMBtu) heat input for larger modified wood-fired boilers. While not required, PM CEMS may be used as an alternative method to demonstrate continuous compliance and as an alternative to opacity monitoring requirements.

Units burning only oil, that contains no more than 0.3 weight percent sulfur, or liquid or gaseous fuels with a potential sulfur dioxide emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input, may demonstrate compliance with the PM standard by maintaining certification of the fuels burned. Such units are not required to conduct PM compliance tests, conduct continuous monitoring, or comply with any other recordkeeping or reporting requirements unless the boiler changes the fuel burned to something other than the certified fuels.

The SO₂ emission limit for new and reconstructed industrial-commercial-institutional steam generating units is 87 ng/J (0.20 lb/MMBtu) heat input, or 92 percent reduction with a maximum emission rate of 520 ng/J (1.2 lb/MMBtu). Compliance with the SO₂ emission limits is determined following similar procedures as in the existing NSPS.

Units burning only oil that contains no more than 0.3 weight percent sulfur or any individual fuel that, when combusted without SO₂ emission control, have an SO₂ emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input are exempt from other SO₂ emission limits and may demonstrate compliance with the SO₂ standard by maintaining certification of the fuels burned. Such units are not required to conduct SO₂ compliance tests, conduct continuous monitoring, or comply with any other recordkeeping or reporting requirements unless the boiler changes the fuel burned to something other than the certified fuels.

An alternate numerical SO₂ limit of 87 ng/J (0.20 lb/MMBtu) heat input has been added both for units presently subject to the NSPS and for modified units. The alternative limit has been made available to units presently subject to the NSPS as well as modified units in recognition of the technical difficulties of facilities firing inherently low sulfur fuels to achieve 90 percent reduction.

C. What are the requirements for small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc)?

The PM emission limit for new and reconstructed small industrial-commercial-institutional steam generating units is 13 ng/J (0.03 lb/MMBtu) heat input for units that burn coal, oil, gas, wood, or a mixture of these fuels with other fuels. The PM emission limit for modified industrial-commercial-institutional steam generating units is 13 ng/J (0.03 lb/MMBtu) heat input or 99.8 percent reduction for units that burn coal, oil, gas, wood, or a mixture of these fuels with other fuels with one exception. The standard for modified wood-fired industrial-commercial-institutional steam generating units is 43 ng/J (0.10 lb/MMBtu) heat input. These limits apply to units between 8.7 MW and 29 MW (30 to 100 MMBtu/h) heat input. While not required, PM CEMS may be used as an alternate method to demonstrate continuous compliance and as an alternative to opacity monitoring.

Units burning only oil that contains no more than 0.5 weight percent sulfur or liquid or gaseous fuels that, when combusted without SO₂ emission control, have a SO₂ emission rate equal to or less than 230 ng/J (0.54 lb/MMBtu) heat input, may demonstrate compliance with the PM standard by maintaining certification of the fuels burned. Such units are not required to conduct PM compliance tests, conduct continuous monitoring, or any other recordkeeping or reporting requirements unless the boiler changes the fuel burned to something other than the certified fuels.

II. Background Information

A. What is the statutory authority for the final rule?

New source performance standards implement CAA section 111(b), and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.

Section 111 of the CAA requires that NSPS reflect the application of the best system of emissions reductions which (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is commonly referred to as best demonstrated technology (BDT).

Section 111(b)(1)(B) of the CAA requires EPA to periodically review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions.

B. What is the regulatory authority for the final rule?

The current standards for steam generating units are contained in the NSPS for electric utility steam generating units (40 CFR part 60, subpart Da), industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db), and small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc).

The NSPS for electric utility steam generating units (40 CFR part 60, subpart Da) were originally promulgated on June 11, 1979 (44 FR 33580) and apply to units capable of firing more than 73 megawatts (MW) (250 MMBtu/h) heat input of fossil fuel that commenced construction, reconstruction, or modification after September 18, 1978. The NSPS also apply to industrial-commercial-institutional cogeneration units that sell more than 25 MW and more than one-third of their potential output capacity to any utility power distribution system. The most recent amendments to emission standards under subpart Da, 40 CFR part 60, were promulgated in 1998 (63 FR 49442) resulting in new NO_x limitations for subpart Da, 40 CFR part 60, units. Furthermore, in the 1998 amendments, the use of output-based emission limits was incorporated.

The NSPS for industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db) apply to units for which construction, modification, or reconstruction commenced after June 19, 1984, that have a heat input capacity greater than 29 MW (100 MMBtu/h). Those standards were originally promulgated on November 25, 1986 (51 FR 42768) and also have been amended since the original promulgation to reflect changes in BDT for these sources. The most recent amendments to emission standards under subpart Db, 40 CFR part 60, were promulgated in 1998 (63 FR 49442) resulting in new NO_x limitations for subpart Db, 40 CFR part 60, units.

The NSPS for small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc) were originally promulgated on September 12, 1990, (55 FR 37674) and apply to units with a maximum heat input capacity greater than or equal to 2.9 MW (10 MMBtu/h) but less than 29 MW (100 MMBtu/h). Those standards apply to units that

commenced construction, reconstruction, or modification after June 9, 1989.

III. Responses to Public Comments

The proposed rule was published February 28, 2005 (70 FR 9706).

A. Electric Utility Steam Generating Units (40 CFR Part 60, Subpart Da) Greenhouse Gases

Comment: One group of commenters state that CAA section 111 requires EPA to set standards of performance for each pollutant emitted by a source category that causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The commenters presented an argument to support their conclusion that carbon dioxide (CO₂) and other greenhouse gases emitted by steam generating units are “reasonably anticipated to endanger public health or welfare.” Thus, EPA must set NSPS for greenhouse gases emitted from steam generating units.

One commenter states that the electricity sector includes the nation’s largest sources of CO₂ emissions, and it is essential that EPA utilize its authority to limit CO₂ emissions under CAA section 111. The commenter states that, in the preamble, EPA alludes to the importance of controlling greenhouse gases, and that EPA revised its earlier position that it did have authority to regulate CO₂; the commenter notes that this position is currently under judicial review. The commenter summarizes the public health dangers from rising CO₂ levels and provides supporting attachments to its submittal. The commenter states that technologies, e.g., integrated gasification combine cycle (IGCC) technology and others, are available to the electric utility industry to reduce CO₂ emissions that were not available in 1979 when the power plant NSPS were promulgated. The commenter attached supporting information on the available technology for lowering CO₂ emissions. For existing sources, the commenter recommends that EPA require States to implement standards of performance for CO₂ from existing sources. According to the commenter, CAA section 111(d) provides that EPA require States to implement standards of performance for existing sources when the pollutant is not regulated as a criteria pollutant. A program of trading CO₂ emission credits is an effective way of regulating CO₂ emissions from existing sources.

One commenter recommends that EPA set CO₂ emission limits as

minimum thermal efficiency levels for boilers.

Response: EPA’s statutory authority for establishing NSPS to control air pollutants from stationary sources is under CAA section 111. EPA has concluded that it does not presently have the authority to set NSPS to regulate CO₂ or other greenhouse gases that contribute to global climate change.

Selection of NO_x Emission Level

Comment: One group of commenters state that to meet the requirements of CAA section 111, EPA must establish a NO_x limit of no more than 0.5 lb/MWh for electric utility steam generating units. The commenters present information and data references to support their selection of a NO_x emission level for the NSPS.

One commenter states that a lower NO_x emission standard of 0.7 or 0.8 lb/MWh is justified based on existing demonstrated technology and is consistent with the mandate in section 111 of the CAA. The commenter cites two fluidized bed boilers that began operating in the late 1980s and have been retrofitted with selective non-catalytic reduction (SNCR) and have actual NO_x emission rates between 0.12 and 0.13 lb/MMBtu.

One commenter states that the standards for NO_x are insufficiently stringent and do not reflect the best system of emission reduction as required by CAA section 111. The commenter provides the following supporting rationale for their view: The 1.0 lb/MWh standard is based on an input-based level of 0.11 lb/MMBtu, which is well above the levels being achieved with recent selective catalytic reduction (SCR) installations. The commenter attached 2003 data showing at least 62 coal-fired plant units achieving a rate of 0.100 lb/MMBtu or below and 37 units emitted at a rate at or below 0.080 lb/MMBtu. New plants should be able to do better. EPA acknowledges that SCR can reduce NO_x emissions by at least 90 percent. Because most existing facilities subject to the final rule are meeting rates of 0.30–0.60 lb/MMBtu without SCR, units with SCR should readily achieve these levels. Even though EPA recognizes that SCR is BDT, it is proposing a less stringent standard based on fluidized beds and advanced combustion controls as an alternative to SCR or SNCR. This contravenes section 111. EPA uses efficiency data for existing plants rather than higher efficiency levels achievable by new plants using either SCR or IGCC technology. A standard closer to the lower end of the range being considered is appropriate.

One commenter states that new coal-fired units can achieve NO_x emission limits of less than 0.500 lb/MWh through the implementation of low NO_x burners and SCR technologies.

One commenter reviewed recent BACT determinations in new source permits for electric utility steam-generating units of more than 250 MMBtu/h (combusting bituminous, sub-bituminous, anthracite and lignite coal) from EPA's Clean Air Technology Center RACT/BACT/LAER Clearinghouse (RBLC) and examined the five most recent permitting decisions. The commenter included RBLC data showing that the permitted NO_x emission limits for all five were 0.07 or 0.08 lb/MMBtu. The commenter states that, as reflected in the RBLC, a limit of 0.08 lb/MMBtu is achievable using SCR and low NO_x burners, and notes that EPA cites SCR as the basis for its proposed limit of 1.0 lb/MWh (equivalent to 0.11 lb/MMBtu). The commenter recommends an output-based standard equivalent to a heat-input based standard between 0.07 and 0.08 lb/MMBtu.

Response: EPA disagrees that the amended NSPS are inappropriate. EPA acknowledges that boiler types and control configurations are technically capable of achieving lower NO_x emissions. EPA has concluded that with advanced combustion controls, coal-fired electric utility steam-generating units are able to achieve a NO_x emissions rate of 1.0 lb/MWh (0.11 lb/MMBtu). The incremental cost of requiring SCR for reduction to 0.7 lb/MWh (0.08 lb/MMBtu) is approximately \$5,000 per ton. The final NO_x standard is based on the best demonstrated technology taking into account costs, other environmental impacts, and additional energy requirements. Requiring SCR in addition to advanced combustion controls not only increases costs and decreases the net efficiency of the unit, but leads to ammonia emissions and catalyst disposal concerns. States and BACT permitting process are still capable of requiring additional controls as appropriate.

NO_x Control for Lignite-Fired Steam-Generating Units

Comment: Several commenters disagree with EPA's assessment of the feasibility of meeting the proposed NO_x limit for lignite-fired boilers. The commenters disagree with EPA's assessment that units burning lignite can meet the proposed NO_x limit with either SCR or fluidized bed combustors and SNCR because EPA is specifying a boiler design that has never been built larger than 300 MW and is generally no

larger than 100 MW. According to the commenter, this violates CAA section 111(b)(5) which prohibits setting a standard based upon a particular technology. One commenter states that information was provided to EPA prior to proposal suggesting that pore pluggage of SCR catalysts makes the proposed limit of 1.0 lb/MWh unachievable at lignite units. According to the commenter, there were no commercial applications of SCR (retrofit or new unit applications) for either northern or southern lignite. One commenter cites published research showing SCR technology ineffective for NO_x reduction from lignite-fired steam-generating units and states that it is unlikely that any new pulverized coal units using Fort Union lignite would install SCR technology to reduce NO_x emissions. The commenter also states that combustion controls, the only effective means to reduce NO_x emissions at some lignite-fired units, have been problematic for Fort Union lignite. The commenter recommends retaining the current NSPS of 1.6 lb/MWh for units burning Fort Union lignite.

Response: EPA disagrees that lignite-fired steam-generating units would not be able to achieve the amended NSPS. While there are no existing lignite-fired electric utility steam-generating units with SCR in the United States, there is considerable experience in the industry to show that use of SCR on lignite is technically feasible. EPA has concluded that the primary reason that no pulverized lignite-fired units are equipped with SCR is because no new pulverized lignite unit has been built in the United States since 1986.

The Electric Power Research Institute testing of SCR catalyst in a slipstream at the Martin Lake Power plant showed acceptable results from Gulf Coast lignite. In addition, two recent permit applications for pulverized lignite-fired utility units in Texas (Twin Oaks 3 and Oak Grove facilities) propose to use SCR to control NO_x emissions to 0.07 and 0.10 lb/MMBtu, respectively. Finally, technology suppliers report that SCR has been successfully used on lignite and brown coal boilers in Europe. EPA has concluded that SCR can be used on lignite boilers in the United States and catalyst suppliers have indicated that they will offer performance guarantees on these applications.

Pore plugging and binding of a catalyst is a common problem experienced by pilot test facilities. In full scale installations, this concern is addressed during the SCR design stage. The methods used to avoid this problem include duct design to promote ash

fallout prior to the SCR, catalyst reactor design to avoid ash buildup, and on-line cleaning methods (soot blowers and sonic horns).

In addition, the use of SCR is not required to comply with the amended NO_x standard. The existing Big Brown facility in Texas burns pulverized Gulf Coast lignite and is able to achieve 0.15 lb NO_x/MMBtu with combustion controls alone. EPA has concluded that new lignite-fired units would either be able to achieve the amended standards without the use of any backend controls or could use SNCR to comply. Existing units at 0.15 lb/MMBtu would only need 30 percent NO_x reduction to comply with the amended NO_x standard. This level of control has been demonstrated for existing pulverized coal (PC) units retrofit with SNCR, and new units could achieve even better results.

Fluidized bed combustion and gasification are also options for new lignite units. The proposed permits for the Westmoreland and South Heart facilities in North Dakota both propose to burn Fort Union lignite in fluidized beds and use SNCR to achieve a NO_x emissions limit of 0.09 lb/MMBtu. With regard to size, Foster Wheeler recently designed a 460 MW supercritical fluidized bed.

Selection of SO₂ Emission Limit

Comment: One group of commenters state that EPA's proposed SO₂ standard for electric utility steam-generating units violates CAA section 111 because it does not reflect BDT for this source category. EPA also did not consider foreign experience or advanced scrubber designs, which indicate lower SO₂ limits have been achieved and are achievable. The processes that have demonstrated greater than 98 percent SO₂ removal and for which vendors offer guarantees greater than 98 percent are the magnesium-enhanced lime ("MEL") flue gas desulfurization (FGD) process, the Chiyoda CT-121 bubbling jet reactor, and circulating fluidized bed scrubbers. Further, design enhancements and additives are available that can increase SO₂ removal efficiencies above 98 percent for other technologies within this general class. Also, EPA did not consider the use of coal washing in its determination.

Response: EPA has concluded that 98 percent control is possible with certain control and boiler configurations under ideal conditions. The amended SO₂ standard is based on a 30-day average that includes the variability that occurs from non-ideal operating conditions. The best long-term SO₂ control performance data that EPA has available

are for the Harrison, Conemaugh, Northside, Clover, and similar facilities. The amended standards are based on operational data from these facilities. EPA has concluded that this level of control is achievable for a broad range of coal and boiler types.

Comment: One group of commenters state that to meet the requirements of CAA section 111, EPA must establish a SO₂ limit of no more than 0.9 lb/MWh for all utility steam-generating units. Alternatively, if EPA finds that this standard would be cost-prohibitive for high sulfur coal, then it should either set emissions limits on a sliding scale that reflects BDT for coals of increasing sulfur content, or establish both stringent emissions limits and stringent percentage reduction requirements that would apply simultaneously. The commenters' review of proposed and final emission limits in recent permits and permit applications for 32 recent coal-fired steam-generating unit projects found 9 units with emissions limits of 0.10 lb/MMBtu or lower (0.95 lb/MWh or lower, assuming 36 percent efficiency) and 22 units with emission limits of 0.13 lb/MMBtu or lower (1.2 lb/MWh or lower).

One commenter states that the standard for SO₂ is insufficiently stringent and does not reflect the best system of emission reduction as required by CAA section 111. The commenter provides the following supporting rationale:

- About 70 percent of coals in use can meet the proposed limit with add-on controls. The data before EPA supports a limit at the low end of the range being considered by EPA (0.90–2.0 lb/MWh) rather than the proposed level (2.0 lb/MWh), which is at the top of the range.

- All coals currently in use can meet a more stringent standard, e.g., 88 percent of coals currently in use can meet 1.1 lb/MWh without pretreatment and using wet lime FGD that consistently achieves a 97 percent reduction; EPA has determined that reductions greater than 98 percent are demonstrated.

- For high sulfur coals, other technologies are available, e.g., IGCC technology which is capable of reductions of over 99 percent. The highest sulfur coals (uncontrolled level of 7.92 lb/MMBtu) can meet 1.1 lb/MWh using technologies that reduce sulfur levels by 99 percent. Other options for meeting more stringent standards include coal washing and blending with low sulfur coals.

- Actual 2003 emissions data show 25 plants with scrubbers achieving emissions at or below 0.10 lb/MMBtu (data attached to commenter's

submittal). EPA's BACT/LAER clearinghouse establishes permitted levels for new scrubbers below the proposed standard and as low as 0.06 lb/MMBtu; IGCC units show even lower permitted levels, 0.03 and 0.032 lb/MMBtu.

- Vendors of scrubber report removal efficiencies of 99.5 percent of sulfur from high sulfur coal (as high as 4 percent) achieving SO₂ emission rates of 0.04 lb/MMBtu. The commenter attached a supporting report by a vendor of scrubber equipment.

- New Source Review (NSR) enforcement settlements reflect better emission rates than 0.21 lb/MMBtu even at existing plants. EPA routinely obtains commitments for FGD retrofits to meet rates of 0.100 to 0.130 lb/MMBtu. The commenter attached supporting consent decrees.

- EPA's proposed standards rely on an estimate that new plants will operate at a 36 percent gross efficiency even though the top 10 percent of existing units operate at 38 percent. This is unreasonable given that the standards will govern new PC plants, with new supercritical plants able to achieve a net efficiency of 45 percent and a gross efficiency of 40 percent.

One commenter states that new coal-fired units can achieve SO₂ emission limits of 0.500 to 1.5 lb/MWh depending on sulfur content. The commenter supports lower SO₂ limits for lower sulfur coal and suggests that this can be done by maintaining a percent reduction requirement or setting a range of SO₂ limits based on sulfur content of coal. The commenter recommends that where a percent reduction limit is used, it should be in addition to the emission rate limit.

One commenter recommends an output-based limit equivalent to a heat-input based limit of 0.10 lb/MMBtu. Based on a survey of EPA's RBLC for recent permitting decisions, permitted SO₂ levels of 0.022 to 0.12 lb/MMBtu, are common State requirements. EPA's argument for a higher limit to account for the highest-sulfur coal is flawed because industry can use lower sulfur coal or use technologies to reduce SO₂ emissions beyond the proposed level.

Response: EPA acknowledges that certain boiler and coal configurations are technically capable of achieving SO₂ emissions rates of 1.0 lb/MWh. The NSPS are based on limits that can be achieved on a consistent basis for a broad range of boiler and coal types. High sulfur coals are an important part of the United States energy resources, and spray dryers for SO₂ control are important in locations with limited water resources. EPA has concluded

that it is vital that the amended NSPS preserve the use of both high sulfur coals and spray dryers. Therefore, EPA is amending the SO₂ standard to allow units greater flexibility in complying with the final SO₂ standard. The amended SO₂ standard is either 1.4 lb/MWh or 95 percent reduction on a 30-day rolling average. The numerical limit is aggressive, but preserves the ability of approximately half the coals presently used in the United States to use spray dryers. The percent maximum reduction requirement is similarly aggressive, but preserves the ability of units to burn high sulfur coals. Based on the sulfur content of coals presently being burned in the United States, EPA has concluded that the majority of new units will comply with the 1.4 lb/MWh standard, but has provided the maximum percent reduction requirement to address the concerns of users of high sulfur coals. The BACT permitting process and states requirements are able to require additional controls as appropriate.

Comment: One commenter states that many scrubbers used for high sulfur coals—3 to 4 percent sulfur—will be unable to meet the proposed SO₂ limit of 2.0 lb/MWh on a consistent basis. According to the commenter, EPA has based their decision on a single, high performance magnesium-enhanced lime scrubber, i.e., the Harrison facility in Pennsylvania. The commenter states that the specialty agent used at the unit may not be broadly available and brings into question whether the SO₂ levels being attained at this plant can be sustained long term. The commenter also states that EPA's use of a scrubber at a single facility as the basis for the SO₂ limit is in conflict with CAA section 111(b)(5), which prohibits setting a standard based upon a particular technology.

The commenter continues by stating that there is considerable uncertainty that the high removal efficiency that would be required for high sulfur coals can consistently and broadly be achieved. According to the commenter, coals with sulfur content exceeding 2.5 percent would require removal efficiencies of up to 98 percent; for these coals, wet scrubbers are the sole option and uncertainties in meeting the NSPS may dissuade some from using such coals.

Response: The final rule amendments allow units to either comply with an output-based limit of 1.4 lb/MWh or demonstrate 95 percent reduction. The maximum percent reduction requirement is achievable for multiple boiler and control configurations and addresses concerns of the use of high sulfur fuels.

Particulate Matter Emission Limit

Comment: One commenter states that fabric filters, the technology on which the proposed PM emission standard is based, is problematic with coals whose sulfur content exceeds 1.5 percent. With only 134 of 1,250 U.S. coal-fired power plants using fabric filters, the commenter notes that with the exception of a limited number of applications on small atypical boilers, there are no fabric filters in operation on plants firing sulfur greater than 2.0 percent by weight. The commenter cites an example of a plant that encountered problems after installing a fabric filter on a unit burning medium-or high-sulfur coal. For this reason, the commenter states that EPA's proposed PM standard is neither achievable nor adequately demonstrated for all coals.

Response: In general, EPA disagrees with the comment that the use of fabric filters to control PM emissions is problematic for electric utility steam generating units firing coals with sulfur contents exceeding 1.5 percent. The example cited by the commenter is for a retrofit application of a fabric filter at an existing facility for which the temperature of the flue gas in the fabric filter unit was not maintained above the acid dew point. Consequently, acid mist formed in the flue gas, condensed on the bags and internal components of the unit, and adversely impacted the performance of the control device. Based on discussions with fabric filter equipment suppliers, EPA has concluded that a similar problem should not occur in fabric filters installed on new and reconstructed facilities because of the capability at these sites to incorporate design options that will maintain the temperature of the flue gas passing through the fabric filter at levels above the acid dew point of the flue gas. These options include use of high temperature bags and injection of hydrated lime to lower the acid dew point of the flue gas. The Department of Energy sponsored two demonstration projects (SNOX Flue Gas Cleaning Demonstration Project (SNOX) and SO_x-NO_x-RO_x-Box Flue Gas Cleanup Demonstration Project (SNRB) projects) that successfully used fabric filters for PM control for electric utility steam generating units burning high sulfur coal, potential SO₂ emissions of 5 and 6 lb/MMBtu, respectively. In addition, two recent permit applications propose to use fabric filters for PM control while burning relatively high sulfur coals. The Longview power plant in West Virginia is proposing to burn 2.5 percent sulfur coal, and the Elm Road plant is proposing to burn coal

with potential SO₂ emissions of 4 lb/MMBtu.

EPA recognizes that in certain site-specific situations where an existing electric utility steam generating unit becomes subject to the NSPS because of modifications to the unit, replacement of an electrostatic precipitator (ESP) with a fabric filter could be problematic. Not all locations may be able to cost-effectively maintain the temperature of the flue gas in a fabric filter above the acid dew point of the flue gas because of existing site conditions and space constraints. Therefore, EPA decided it is appropriate to establish a separate PM standard for modified sources subject to subpart Da, 40 CFR part 60. Owners and operators of modified electric utility steam generating units subject to the NSPS are given the option of meeting either a 0.015 lb/MMBtu or 99.8 percent reduction standard. ESPs can be modified to cost-effectively achieve this level of control.

Comment: One commenter takes issue with EPA's proposed input-based standard for PM emissions. According to the commenter, although EPA determined that ESPs and fabric filters are the best demonstrated technology for controlling filterable particulate matter, EPA's justification for the revised PM limit is based on three plants where fabric filtration is used. The commenter also states that of the three plants, two use fluidized bed boilers, which use limestone as an active bed material, significantly altering the nature of the PM generated for collection. The commenter states that the record does not support the proposed NSPS for PM for ESPs or that fluidized bed combustors are appropriate units on which to base PM standards for pulverized coal steam generating units, which are projected to make up the majority of new units.

Response: EPA has gathered additional stack test data that indicates an ESP could be used by the majority of coal types to comply with the final rule amendments. Based on ESP cost models, they are often less expensive than fabric filters for high sulfur applications. Additional information is available in the PM control cost memorandum.

Comment: One group of commenters state that the proposed opacity limit does not reflect BDT because the proposed rule retains the existing opacity limit of 20 percent. The commenters state that this limit is over 20 years old, and is not based on the performance of modern baghouse control systems. Because EPA has acknowledged in the proposed rule that the former 0.03 lb/MMBtu PM limit

should at least be halved to 0.015 lb/MMBtu, there should be a proportionate halving of the opacity limit, from 20 percent to 10 percent. Ten percent opacity can be easily and continuously attained by subpart Da, 40 CFR part 60, facilities using appropriate control technology. There are existing power plants around the country with BACT limits of 10 percent for opacity, including the Sevier Power Company—Sigurd plant in Utah, Intermountain Power in Utah, and Plum Point Energy in Arkansas.

Response: Since opacity is used as an indication on PM emissions, EPA has provided sources with two options to demonstrate continuous compliance with the amended PM standard. Sources may elect to install and operate PM CEMS and demonstrate compliance each boiler operating day. For these units, opacity monitoring shall no longer be required. Units that do not install PM CEMS shall perform stack tests to demonstrate compliance and shall still be subject to the existing 6-minute opacity limit. In addition, sources shall use bag leak detectors or monitor ESP parameters in addition to developing a site-specific opacity trigger level that is based on the opacity during the stack test. Sources that deviate from this opacity or other parameter are required to perform a stack test within 60 days of the deviation. Stack opacity characteristics are different for fabric filters and ESP. Therefore, EPA has concluded that a site-specific opacity trigger is the best approach to monitor continuous compliance.

B. Industrial-Commercial-Institutional and Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subparts Db and Dc)

Comment: Several commenters opposed both the proposed single SO₂ limit of 0.24 lb/MMBtu heat input and the limit of either 0.15 lb/MMBtu heat input or 95 percent reduction for a variety of reasons. Several commenters believed that these approaches would discourage the use of high sulfur coals found in the Midwest and would be difficult to meet consistently for circulating fluidized bed boilers and boilers burning low sulfur coal. They also stated that industrial boilers cannot routinely achieve high percent reductions of 95 percent or more, as would be required to meet these standards, because of variations in coal quality and operational variations due to fluctuations in steam demand. Also, meeting 95 percent reduction would not be feasible for existing units that are modified. Three of the commenters recommended adopting the same SO₂

standard as subpart Da, 40 CFR part 60 (90 percent reduction with a 70 percent reduction for units that demonstrate emissions below 0.20 lb/MMBtu heat input). Two commenters recommended retaining the current 90 percent SO₂ reduction requirement with an alternative emission limit of 0.24 lb/MMBtu heat input. One commenter supported EPA's decision that the current SO₂ emission limits in subparts Db and Dc of 40 CFR part 60 should not be amended because option 1 and 2 would impose unacceptable compliance costs and are not warranted. One commenter also opposed reducing the SO₂ limit for units with heat input capacities of 10–75 MMBtu/h.

Several commenters maintained that the changes to the SO₂ limit to remove the percent reduction requirement should apply to existing units as well as new units. Excluding existing units from the change would provide a disincentive to use low sulfur coal and would not provide relief for existing compliance problems. Many existing boilers were designed to achieve 90 percent reduction using high sulfur coals. An existing unit that wanted to switch to low sulfur coal would have difficulty in meeting a 90 percent requirement using existing control equipment. Also, circulating fluidized bed (CFB) boilers that use low sulfur coal have had difficulty in achieving a 90 percent reduction consistently. The technical impossibility of measuring uncontrolled SO₂ emissions at a CFB unit creates an inherent difficulty in adjusting limestone injection rate to accommodate short-term variations in coal sulfur content. One such unit that burns low sulfur coal has been cited for short-term violations of the NSPS even though average emissions were in the range of 0.13 lb/MMBtu (0106).

Response: After considering all the comments and additional information provided by commenters, we have decided to provide industrial units the following options. Units presently subject to the NSPS and modified units may reduce SO₂ emissions by 90 percent or meet an SO₂ emission limit of 0.20 lb/MMBtu heat input. New and reconstructed units that become subject to the NSPS after February 28, 2005, may reduce SO₂ emissions by 92 percent or meet an SO₂ emission limit of 0.20 lb/MMBtu heat input. This approach will be more stringent than the existing subpart Db, 40 CFR part 60, requirements, and at the same time allow units with difficulty in achieving high levels of SO₂ control to overcome compliance demonstrations problems by burning low sulfur fuels.

IV. Impacts of the Final Rule?

A. What are the impacts for electric utility steam generating units (40 CFR part 60, subpart Da)?

We estimate that 5 new electric utility steam generating units will be installed in the United States over the next 5 years and affected by the final rule. All of these units will need to install add-on controls to meet the PM, SO₂, and NO_x limits required under the final rule. However, these boilers will already be required to install add-on PM, SO₂, and NO_x controls to meet the reduction requirements of the existing NSPS. Compared to the existing NSPS, the incremental PM, SO₂, and NO_x reductions resulting from the final rule will be 530 tons of PM, 8,400 tons of SO₂, and 1,400 tons of NO_x. Using this comparison, the annualized cost of the final utility amendments are \$4.4 million.

Using this comparison, we expect the final rule to result in an increase in electrical supply generated by unaffected sources (e.g., existing electric utility steam generating units), we have concluded that this will not result in higher NO_x, SO₂, and PM emissions from these sources. Other emission control programs such as the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), and PSD/NSR already promote or require emission controls that would effectively prevent emissions from increasing. All the emissions reductions estimates and assumptions have been documented in the docket to the final rule.

A more accurate assessment of the emissions reductions and annualized costs of the final utility amendments include other regulatory programs that are presently requiring controls beyond what is required by the existing NSPS. The BACT permitting process requires new sources to install controls at or beyond what the final NSPS amendments require. In addition, the recently finalized CAIR and CAMR rules, along with the proposed revisions to ambient particulate matter standards, will push permits even lower. The amended NSPS reflect the levels of control presently being required by these other programs. Therefore, the actual environmental benefits and cost impacts of the final rule are essentially zero. A more detailed discussion of the cost and emissions impacts of the amended NSPS is available in the docket.

B. What are the impacts for industrial-commercial-institutional boilers (40 CFR part 60, subparts Db and Dc)?

We estimate that approximately 186 new industrial-commercial-institutional boilers will be installed in the United States over the next 5 years and affected by the final rule. All of these units will need to install add-on controls to meet the PM and SO₂ limits required under the final rule. However, these new boilers will already be required to install add-on PM and SO₂ controls to meet the existing NSPS. The new source requirements under the maximum achievable control technology (MACT) program and PSD/NSR require new units presently to install controls beyond what is required by the existing NSPS.

Wood-fired boilers are the only industrial sources that could potentially use the alternative compliance limit in the boiler MACT and would not be required to meet the new source MACT limit. We estimate that 17 new wood-fired boilers will be installed in the United States over the next 5 years and affected by the final rule. Using the existing NSPS as a baseline, the additional annualized costs are \$2.2 million, and the PM emissions reductions are 930 tons. EPA has concluded that new wood-fired units will not use the compliance alternatives available in the boiler MACT and that they will comply with the new source PM limit of 0.025 lb/MMBtu. Due to PSD/NSR and the limited applicability of the alternate compliance limit to new units, it will primarily only be used by existing wood-fired boilers. Thus, we concluded that the PM and SO₂ reductions and costs resulting from the final rule will essentially be zero.

C. What are the economic impacts?

Even though actual costs and benefits are essentially zero, EPA prepared an economic impact analysis comparing the existing NSPS with the amended NSPS to evaluate the impacts the final rule will have on electric utilities and consumers of goods and services produced by electric utilities. The analysis showed minimal changes in prices and output for products made by the industries affected by the final rule. The price increase for affected output is less than 0.003 percent, and the reduction in output is less than 0.003 percent for each affected industry. Estimates of impacts on fuel markets show price increases of less than 0.01 percent for petroleum products and natural gas, and price increases of 0.04 and 0.06 percent for base-load and peak-load electricity, respectively. The price

of coal is expected to decline by about 0.002 percent, and that is due to a small reduction in demand for this fuel type. Reductions in output are expected to be less than 0.02 percent for each energy type, including base-load and peak-load electricity.

D. What are the social costs and benefits?

The social costs of the final rule are estimated at \$0.4 million (2002 dollars). Social costs include the compliance costs, but also include those costs that reflect changes in the national economy due to changes in consumer and producer behavior in response to the compliance costs associated with a regulation. For the final rule, changes in energy use among both consumers and producers to reduce the impact of the regulatory requirements of the rule lead to the estimated social costs being less than the total annualized compliance cost estimate of \$6.5 million. The primary reason for the lower social cost estimate is the increase in electricity supply generated by unaffected sources (e.g., existing electric utility steam generating units), which offsets mostly the impact of increased electricity prices to consumers. The social cost estimates discussed above do not account for any benefits from emission reductions associated with the final rule.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), EPA must determine whether the regulatory action is "significant" and, therefore, subject to review by OMB and the requirements of the Executive Order. The Executive Order defines "significant regulatory action" as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of \$100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, OMB has notified EPA that it considers the final rule amendments a "significant regulatory action" within the meaning of the Executive Order. EPA has submitted this action to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the public record.

B. Paperwork Reduction Act

The final rule amendments do not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The final rule amendments result in no changes to the information collection requirements of the existing standards of performance and would have no impact on the information collection estimate of project cost and hour burden made and approved by OMB during the development of the existing standards of performance. Therefore, the information collection requests have not been amended. The OMB has previously approved the information collection requirements contained in the existing standards of performance (40 CFR part 60, subparts Da, Db, and Dc) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, at the time the standards were promulgated on June 11, 1979 (40 CFR part 60, subpart Da, 44 FR 33580), November 25, 1986 (40 CFR part 60, subpart Db, 51 FR 42768), and September 12, 1990 (40 CFR part 60, subpart Dc, 55 FR 37674). The OMB assigned OMB control numbers 2060-0023 (ICR 1053.07) for 40 CFR part 60, subpart Da, 2060-0072 (ICR 1088.10) for 40 CFR part 60, subpart Db, 2060-0202 (ICR 1564.06) for 40 CFR part 60, subpart Dc. Copies of the information collection request document(s) may be obtained from Susan Auby by mail at U.S. EPA, Office of Environmental Information, Collection Strategies Division (2822T), 1200 Pennsylvania Avenue, NW., Washington, DC 20460, by e-mail at auby.susan@epa.gov, or by calling (202) 566-1672. A copy may also be downloaded off the Internet at <http://www.epa.gov/icr>.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any

previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The 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 (RFA) 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 rules on small entities, small entity is defined as follows: (1) A small business that is an ultimate parent entity in the regulated industry that has a gross annual revenue less than \$6.5 million (this varies by industry category, ranging up to \$10.5 million for North American Industrial Classification System (NAICS) code 562213 (VSMWC)), based on Small Business Administration's size standards; (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; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's final rule amendments on small entities, we conclude that this action will not have a significant economic impact on a substantial number of small entities. We have determined for electric utility steam generating units, based on the existing inventory for the corresponding NAICS code and presuming the percentage of entities that are small in that inventory (estimated to be 3 percent) is representative of the percentage of small entities owning new utility boilers in the 5th year after promulgation, that at most, one entity out of five new entities in the industry may be small entities and thus affected by the final rule amendments.

We have determined for industrial-commercial steam generating units,

based on the existing industrial boilers inventory for the corresponding NAICS codes and presuming the percentage of small entities in that inventory is representative of the percentage of small entities owning new wood-fueled industrial boilers in the 5th year after promulgation, that between two and three entities out of 17 in the industry with NAICS code 321 and 322 may be small entities, and thus affected by the final rule amendments.

Based on the boiler size definitions for the affected industries (subpart Db of 40 CFR part 60: greater than or equal to 100 MMBtu/h; subpart Dc of 40 CFR part 60: 10–100 MMBtu/h), EPA determined that the firms being affected were likely to fall under the subpart Dc of 40 CFR part 60 boiler category. These two or three affected small entities are estimated to have annual compliance costs between \$70 and \$105 thousand which represents less than 5 percent of the total compliance cost for all affected wood-fired industrial boilers. Based on the average employment per facility data from the U.S. Census Bureau, for the corresponding NAICS codes under the subpart Db of 40 CFR part 60 and subpart Dc of 40 CFR part 60 categories, the compliance cost of these facilities is expected to be less than 1 percent of their estimated sales. For more information on the results of the analysis of small entity impacts, please refer to the economic impact analysis in the docket.

Although the final rule amendments will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of the final rule amendments on small entities. In the final rule amendments, the Agency is applying the minimum level of control and the minimum level of monitoring, recordkeeping, and reporting to affected sources allowed by the CAA. This provision should reduce the size of small entity impacts.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act (UMRA) of 1995, Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with “Federal mandates” that may result in expenditures by State, local, and Tribal governments, in the aggregate, or by the private sector, of \$100 million or more in any 1 year. Before promulgating an EPA rule for

which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if EPA publishes with the final rule an explanation why that alternative was not adopted.

Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, EPA must develop a small government agency plan under section 203 of the UMRA. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA’s regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that the final rule amendments contain no Federal mandates 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, the final rule amendments are not subject to the requirements of section 202 and 205 of the UMRA. In addition, we determined that the final rule amendments contain no regulatory requirements that might significantly or uniquely affect small governments because the burden is small and the regulation does not unfairly apply to small governments. Therefore, the final rule amendments are not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132 (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.”

The final rule amendments do not have federalism implications. They 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. The final rule amendments 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 the final rule amendments.

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

Executive Order 13175, (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure “meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications.” “Policies that have Tribal implications” is defined in the Executive Order to include regulations that have “substantial direct effects on relationship between the Federal Government and the Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.”

The final rule amendments do not have tribal implications, as specified in Executive Order 13175. They will not have substantial direct effects on tribal governments, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the final rule amendments.

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

Executive Order 13045 (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be “economically significant” as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, EPA must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives EPA considered.

EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety

risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. The final rule amendments are not subject to Executive Order 13045 because they are based on technology performance and not on health and safety risks.

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

This action is not a “significant energy action,” as defined in Executive Order 13211, because it is not likely to have a significant adverse effect on the supply, distribution, or energy use. Further, we concluded that this action is not likely to have any adverse energy effects.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. No. 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in their regulatory and procurement 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, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

Today’s action does not involve any new technical standards or the incorporation by reference of existing technical standards. Therefore, the consideration of voluntary consensus standards is not relevant to today’s action.

J. 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 the Congress and to the Comptroller General of the United States. EPA will submit a report containing today’s action 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 rule in the **Federal Register**. A major rule cannot

take effect until 60 days after it is published in the **Federal Register**. Today’s action is not a “major rule” as defined by 5 U.S.C. 804(2). The final rule amendments will be effective February 27, 2006.

List of Subjects in 40 CFR Part 60

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

Dated: February 9, 2006.

Stephen L. Johnson,
Administrator.

■ 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 Da—[Amended]

■ 2. Section 60.40Da is amended by revising paragraph (b) to read as follows:

§ 60.40Da Applicability and designation of affected facility.

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

■ 3. Section 60.41Da is amended by revising the definitions of “Boiler operating day,” “Cogeneration,”

“Electric utility steam-generating unit,” and “Gross output” and by adding in alphabetical order the definitions of “ISO conditions” and “Petroleum” to read as follows:

§ 60.41Da Definitions.

Boiler operating day for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Cogeneration, also known as “combined heat and power,” means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Electric utility steam-generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. For the purpose of this subpart, net-electric output is the gross electric sales to the utility power distribution system minus purchased power on a 12-month rolling average. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

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 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 (i.e., steam delivered to an industrial process).

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60

percent, and a pressure of 101.3 kilopascals.

* * * * *

Petroleum means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate, residual oil, and petroleum coke.

* * * * *

■ 4. Section 60.42Da is amended by revising the introductory text in paragraph (a) and adding paragraphs (c) and (d) to read as follows:

§ 60.42Da Standard for particulate matter.

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

* * * * *

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

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

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

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

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

(2) 0.1 percent of the combustion concentration determined according to

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

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

■ 5. Section 60.43Da is amended by revising the introductory text in paragraphs (a) and (b) and adding paragraphs (i), (j), and (k) to read as follows:

§ 60.43Da Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain sulfur dioxide in excess of:

* * * * *

(b) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain sulfur dioxide in excess of:

* * * * *

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

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

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

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

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

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

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

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

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

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

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(j) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

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

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

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that

contain sulfur dioxide in excess of either:

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

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

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

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

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, and that is located in a noncontinental area, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/MMBtu) heat input on a 30-day rolling average basis.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of if the affected facility or 230 ng/J (0.54 lb/MMBtu) heat input on a 30-day rolling average basis.

■ 6. Section 60.44Da is amended by revising paragraph (d) and adding paragraphs (e) and (f) to read as follows:

§ 60.44Da Standard for nitrogen oxides.

* * * * *

(d)(1) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no new source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction commenced after July 9, 1997, but before or on February

28, 2005, any gases that contain nitrogen oxides (expressed as NO₂) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average, except as provided under § 60.48Da(k).

(2) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no existing source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which reconstruction commenced after July 9, 1997, but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO₂) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average.

(e) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except for an IGCC meeting the requirements of paragraph (f) of this section, any gases that contain nitrogen oxides (expressed as NO₂) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO₂) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under § 60.48Da(k).

(2) For an affected facility for which reconstruction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO₂) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO₂) in excess of either:

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

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis.

(f) On and after the date on which the performance test required to be conducted under § 60.8 is completed, the owner or operator of an IGCC subject to the provisions of this subpart that burns liquid fuel as a supplemental fuel and for which construction, reconstruction, or modification commenced after February 28, 2005, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO₂) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided for in paragraphs (f)(2) and (3) of this section.

(2) When burning liquid fuel exclusively or in combination with synthetic gas derived from coal such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO₂) in excess of 190 ng/J (1.5 lb/MWh) gross energy output on a 30-day rolling average basis.

(3) In cases when during a 30-day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO₂) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

■ 7. Section 60.48Da is amended by revising paragraphs (g), (i), (k) introductory text, (k)(1) introductory text, (k)(2) introductory text, and adding paragraphs (m), (n), (o), and (p) to read as follows:

§ 60.48Da Compliance provisions.

* * * * *

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

(1) Compliance with applicable 30-day rolling average SO₂ and NO_x emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO₂ and NO_x for the 30 successive boiler operating days, except for data obtained during

startup, shutdown, malfunction (NO_x only), or emergency conditions (SO₂) only.

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

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

* * * * *

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

* * * * *

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

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

* * * * *

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

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

* * * * *

(m) *Compliance provisions for sources subject to § 60.43Da(i)(1)(i) or (j)(1)(i).* The owner or operator of an affected facility subject to § 60.43Da(i)(1)(i) or (j)(1)(i) shall calculate SO₂ emissions by

multiplying the average hourly SO₂ output concentration, measured according to the provisions of § 60.49Da(b), by the average hourly flow rate, measured according to the provisions of § 60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of § 60.49Da(k).

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

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

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

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

(3) An owner or operator using an ESP to comply with the applicable emission limits shall use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP. Baseline parameters shall be

established as average rates measured during the performance test. If a 3-hour average voltage and secondary current average deviates more than 10 percent from the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test, and

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

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

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

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

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

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

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

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

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

(5) An owner or operator of a modified affected source electing to meet the emission limitations in

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

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

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

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

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

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

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

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

(ii) [Reserved]

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

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

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

■ 8. Section 60.49Da is amended by revising paragraphs (a), (b)(2), (f), (k)(3), (l), and (o), and adding paragraphs (t), (u), and (v) to read as follows:

§ 60.49Da Emission monitoring.

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

(b) * * *

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

* * * * *

(f)(1) For units that began construction, reconstruction, or

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

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

* * * * *

(k) * * *

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

* * * * *

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

* * * * *

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

measure the flow of exhaust gases discharged to the atmosphere.

* * * * *

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

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

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

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

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

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

(2) During each relative accuracy test run of the continuous emission

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

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

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

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

■ 9. Section 60.50Da is amended by revising paragraph (g)(2) to read as follows:

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(g) * * *

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

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

Where:

ER_{cogen} = Cogeneration Hg emission rate over a compliance period in lb/MWh;

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

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

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

* * * * *

Subpart Db—[Amended]

■ 10. Section 60.40b is amended by revising paragraph (i) and adding paragraphs (k) and (l) 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. This subpart will continue to apply to all

other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

* * * * *

(k) Any facility covered by subpart Eb or subpart AAAA of this part is not covered by this subpart.

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

■ 11. Section 60.41b is amended by adding the definition of “Cogeneration” in alphabetical order and revising the definition of “Very low sulfur oil” to read as follows:

§ 60.41b Definitions.

* * * * *

Cogeneration, also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

* * * * *

Very low sulfur oil for units constructed, reconstructed, or modified on or before February 28, 2005, means an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide 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, *very low sulfur oil* means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

* * * * *

■ 12. Section 60.42b is amended by revising paragraphs (a) introductory text, (b), (d) introductory text, and (d)(3) and by adding paragraphs (d)(4) and (k) to read as follows:

§ 60.42b Standard for sulfur dioxide.

(a) Except as provided in paragraphs (b), (c), (d), (j), or (k) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, 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 or oil shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential sulfur dioxide emission rate (90 percent reduction) and the emission limit determined according to the following formula:

* * * * *

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, 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 sulfur dioxide in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential sulfur dioxide 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.

* * * * *

(d) On and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever comes first, no owner or operator of an affected facility listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/million Btu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/million Btu) 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).

* * * * *

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat input to the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat input to the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with any other gaseous fuels.

* * * * *

(k) On or 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 or reconstruction after February 28, 2005, and that combusts coal, oil, 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 sulfur dioxide in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential sulfur dioxide emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input, except as provided in paragraphs (k)(1) or (k)(2). Affected facilities subject to this paragraph are also subject to paragraphs (e) through (g) of this section.

(1) Units firing only oil that contains no more than 0.3 weight percent sulfur or any individual fuel with a potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from all other sulfur dioxide emission limits in this paragraph.

(2) Units that are located in a noncontinental area and that combust coal or oil shall not discharge any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 230 ng/J (0.54 lb/MMBtu) heat input if the affected facility combusts oil.

■ 13. Section 60.43b is amended by adding paragraph (h) to read as follows:

§ 60.43b Standard for particulate matter.

* * * * *

(h)(1) On or 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, gas, 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 particulate matter emissions in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5).

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under § 60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the

atmosphere from any affected facility for which modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels, and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On or 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 modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On or 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 modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On or 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 only oil that contains no more than 0.3 weight percent sulfur or other liquid or gaseous fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less is not subject to the PM or opacity limits in this section.

■ 14. Section 60.44b is amended by adding paragraph (l)(3) to read as follows:

§ 60.44b Standard for nitrogen oxides.

* * * * *

(l) * * *

(3) After February 27, 2006, units may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of § 60.46a (i)(1), and must monitor emissions according to § 60.47a(c)(1), (c)(2), (k), and (l).

■ 15. Section 60.45b is amended by revising the introductory text in paragraph (c) and adding paragraph (k) to read as follows:

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

* * * * *

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential sulfur dioxide emission rate (% P_s) and the sulfur dioxide emission rate (E_s) pursuant to § 60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

* * * * *

(k) Units that burn only oil that contains no more than 0.3 weight percent sulfur or fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less may demonstrate compliance by maintaining records of fuel supplier certifications of sulfur content of the fuels burned.

■ 16. Section 60.46b is amended by revising paragraphs (a) and (b) and adding paragraphs (i) and (j) to read as follows:

* * * * *

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

(a) The particulate matter emission standards and opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction, and as specified in paragraphs (i) and (j) of this section. The nitrogen oxides emission standards under § 60.44b apply at all times.

(b) Compliance with the particulate matter emission standards under § 60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) and (j).

* * * * *

(i) Units burning only oil that contains no more than 0.3 weight percent sulfur or liquid or gaseous fuels with a potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less may demonstrate compliance by maintaining fuel

supplier certifications of the sulfur content of the fuels burned.

(j) In place of particulate matter testing with EPA Reference Method 5, 5B, or 17, an owner or operator may elect to install, calibrate, maintain, and operate a continuous emission monitoring system for monitoring particulate matter 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 particulate matter emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 shall comply with the requirements specified in paragraphs (j)(1) through (j)(13) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the continuous monitoring system if the owner or operator was previously determining compliance by Method 5, 5B, or 17 performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for particulate matter emissions as required under § 60.8 of subpart A of this part. Compliance with the particulate matter emission limit shall be determined by using the continuous emission monitoring system specified in paragraph (j) of this section to measure particulate matter and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19, section 4.1.

(6) Compliance with the particulate matter emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using continuous emission monitoring system outlet data.

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

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

(8) The 1-hour arithmetic averages required under paragraph (j)(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 continuous emission monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (j)(7) of this section are not met.

(10) The continuous emission monitoring system shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraphs (j)(7)(i) of this section.

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

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

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

(13) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

■ 17. Section § 60.47b is amended by revising paragraphs (a) and (d), and adding paragraph (g) to read as follows:

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b),(f), and (g) of this section, the owner or operator of an affected facility subject to the sulfur dioxide standards under § 60.42b shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS)

for measuring sulfur dioxide concentrations and either oxygen (O₂) or carbon dioxide (CO₂) concentrations and shall record the output of the systems. The sulfur dioxide and either oxygen or carbon dioxide concentrations shall both be monitored at the inlet and outlet of the sulfur dioxide control device.

* * * * *

(d) The 1-hour average sulfur dioxide emission rates measured by the CEMS required by paragraph (a) of this section and required under § 60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under § 60.42(b). Each 1-hour average sulfur dioxide emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to § 60.13(h)(2). Hourly sulfur dioxide emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determining of a steam generating unit operating day.

* * * * *

(g) Units burning any fuel with a potential sulfur dioxide emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are not required to conduct emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

■ 18. Section 60.48b is amended by revising paragraphs (a), (b) introductory text, (d), and adding paragraphs (j) and (k) to read as follows:

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

(a) The owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system, except as provided in paragraphs (j) and (k) of this section.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a nitrogen oxides standard under § 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

* * * * *

(d) The 1-hour average nitrogen oxides emission rates measured by the continuous nitrogen oxides monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the

average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2).

* * * * *

(j) Units that burn only oil that contains no more than 0.3 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less are not required to conduct PM emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

(k) Owners or operators complying with the PM emission limit by using a PM CEMs monitor instead of monitoring opacity must calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for PM emissions discharged to the atmosphere as specified in § 60.46b(j). The continuous monitoring systems specified in paragraph § 60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

Subpart Dc—[Amended]

■ 19. Section 60.40c is amended by adding paragraphs (e), (f), and (g) to read as follows:

§ 60.40c Applicability and delegation of authority.

* * * * *

(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. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

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

■ 20. Section 60.41c is amended by revising the definition of coal 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 D388–77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR—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, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

* * * * *

■ 21. Section 60.42c is amended by revising paragraphs (a), (b) introductory text, and (b)(1) to read as follows:

§ 60.42c Standard for sulfur dioxide.

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: Cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 90 percent SO₂ reduction requirement specified in this paragraph and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO₂ emission rate (80 percent reduction), nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 90 percent SO₂ reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

* * * * *

■ 22. Section 60.43c is amended by adding paragraph (e) to read as follows:

§ 60.43c Standard for particulate matter.

* * * * *

(e)(1) On or 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, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2) and (e)(3) of this section. Affected facilities subject to this paragraph, are also subject to the requirements of paragraphs (c) and (d) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under § 60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels, and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On or 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 modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

■ 23. Section 60.45c is amended by revising the introductory text in paragraph (a) and adding paragraphs (c) and (d) to read as follows:

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

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) and (d) of this section.

* * * * *

(c) Units that burn only oil containing no more than 0.5 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 230 ng/J (0.54 lb/MMBtu) heat input or less are not required to conduct emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

(d) In place of particulate matter testing with EPA Reference Method 5, 5B, or 17, an owner or operator may elect to install, calibrate, maintain, and operate a continuous emission monitoring system for monitoring particulate matter 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 particulate matter emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 shall install, calibrate, maintain, and operate a continuous emission monitoring system and shall comply with the requirements specified in paragraphs (d)(1) through (d)(13) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the continuous monitoring system if the owner or operator was previously determining compliance by Method 5, 5B, or 17 performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for particulate matter emissions as required under § 60.8 of subpart A of this part. Compliance with the particulate matter emission limit shall be determined by using the continuous emission monitoring system specified in paragraph (d) of this section to measure particulate matter and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19, section 4.1.

(6) Compliance with the particulate matter emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using continuous emission monitoring system outlet data.

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

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

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (d)(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 continuous emission monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (d)(7) of this section are not met.

(10) The continuous emission monitoring system shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the continuous emission monitoring system required by Performance Specification 11 in

appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraph (d)(7)(i) of this section.

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

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

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

(13) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 75 percent of total

operating hours on a 30-day rolling average.

■ 24. Section 60.47c is amended by revising paragraph (a) and adding paragraphs (c) and (d) to read as follows:

§ 60.47c Emission monitoring for particulate matter.

(a) The owner or operator of an affected facility combusting coal, oil, gas, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system, except as specified in paragraphs (c) and (d) of this section.

* * * * *

(c) Units that burn only oil that contains no more than 0.5 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 230 ng/J (0.54 lb/MMBtu) heat input or less are not required to conduct PM emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

(d) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a continuous

monitoring system, and record the output of the system, for PM emissions discharged to the atmosphere as specified in § 60.45c(d). The continuous monitoring systems specified in paragraph § 60.45c(d) shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

■ 25. Section 60.48c is amended by revising paragraph (g) to read as follows:

§ 60.48c Reporting and recordkeeping requirements.

* * * * *

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The owner or operator of an affected facility that only burns very low sulfur fuel oil or other liquid or gaseous fuels with potential sulfur dioxide emissions rate of 140 ng/J (0.32 lb/MMBtu) heat input or less shall record and maintain records of the fuels combusted during each calendar month.

* * * * *

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