

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60, 63, 72, and 75

[OAR-2002-0056; FRL-]

RIN 2060-AJ65

**Standards of Performance for New and Existing Stationary
Sources: Electric Utility Steam Generating Units**

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY:

In this document, EPA is finalizing the Clean Air Mercury Rule (CAMR) and establishing standards of performance for mercury (Hg) for new and existing coal-fired electric utility steam generating units (Utility Units), as defined in Clean Air Act (CAA) section 111. Today's amendments to CAA section 111 rules would establish a mechanism by which Hg emissions from new and existing coal-fired Utility Units are capped at specified, nation-wide levels. A first phase cap of 38 tons per year (tpy) becomes effective in 2010 and a second phase cap of 15 tpy becomes effective in 2018. Facilities must demonstrate compliance with the standard by holding one "allowance" for each ounce (oz) of Hg emitted in any given year. Allowances are readily transferrable among all regulated facilities. Such a "cap-and-trade" approach to limiting Hg emissions is the most cost effective way to achieve the reductions in Hg

emissions from the power sector.

The added benefit of the cap-and-trade approach is that it dovetails well with the sulfur dioxide (SO₂) and nitrogen oxides (NO_x) emission caps under the final Clean Air Interstate Rule (CAIR) that was signed on March 10, 2005. CAIR establishes a broadly-applicable cap-and-trade program that significantly limit SO₂ and NO_x emissions from the power sector. The advantage of regulating Hg at the same time and using the same regulatory mechanism as for SO₂ and NO_x is that significant Hg emissions reductions, especially reductions of oxidized Hg, can and will be achieved by the air pollution controls designed and installed to reduce SO₂ and NO_x. Significant Hg emissions reductions can be obtained as a "co-benefit" of controlling emissions of SO₂ and NO_x; thus, the coordinated regulation of Hg, SO₂, and NO_x allows Hg reductions to be achieved in a cost effective manner.

This action also finalizes Performance Specification 12A, "Specification and Test Methods for Total Vapor Phase Mercury Continuous Emission Monitoring Systems in Stationary Sources" at 40 CFR part 60, appendix B, and appendix K to 40 CFR part 75, "Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems."

EFFECTIVE DATE: [INSERT DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER].

ADDRESSES: Docket. EPA has established a docket for this

action under Docket ID No. OAR-2002-0056 and legacy Docket ID No. A-92-55. All documents in the docket are listed in the EDOCKET index at <http://www.epa.gov/edocket>. Although listed in the index, some information is not publicly available, i.e., 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 in EDOCKET or in hard copy at the Air and Radiation Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW, Washington, D.C. 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 is (202) 566-1742.

FOR FURTHER INFORMATION CONTACT: For information concerning analyses performed in developing the final rule, contact Mr. William Maxwell, Combustion Group, Emission Standards Division (C439-01), EPA, Research Triangle Park, North Carolina, 27711; telephone number (919) 541-5430; fax number (919) 541-5450; electronic mail address: maxwell.bill@epa.gov.

SUPPLEMENTARY INFORMATION: Regulated Entities. Categories and entities potentially regulated by this action include the following:

Category	NAICS code ¹	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	221122 ²	Fossil fuel-fired electric utility steam generating units owned by the Federal government.
State/local/Tribal government	221122 ²	Fossil fuel-fired electric utility steam generating units owned by municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian Country.

¹ North American Industry Classification System.

² Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists examples of the types of entities EPA is now aware could potentially be regulated by this action. Other types of entities not listed could also be affected. To determine whether your facility, company, business, organization, etc., is regulated by this action, you should examine the applicability criteria in 40 CFR 60.45a of the final NSPS amendments. If you have questions regarding the applicability of this action to a particular entity, consult your State or local agency (or EPA Regional Office) described 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 document will also be available on the WWW through EPA's Technology Transfer Network (TTN). Following signature by the Acting Administrator, a copy of the final rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at <http://www.epa.gov/ttn/oarpg>. The TTN provides information and technology exchange in various areas of air pollution control. If more information regarding the TTN is needed, call the TTN HELP line at (919) 541-5384.

Judicial Review. Under CAA section 307(b), judicial review of the final NSPS is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit on or before **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER]**. Under CAA section 307(D)(7)(B), only those objections to the final rule which were raised with reasonable specificity during the period for public comment may be raised during judicial review. Moreover, under CAA section 307(b)(2), 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.

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- I. Background**
 - A. What is the source of authority for development of the

final rule?

CAA section 111 creates a program for the establishment of "standards of performance". A "standard of performance" is "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction, which (taking into account the cost of achieving such reduction, any non-air quality health and environmental impacts and energy requirements), the Administrator determines has been adequately demonstrated." CAA § 111(a)(1).

For new sources, EPA must first establish a list of stationary source categories, which, the Administrator has determined "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." CAA § 110(b)(1)(A)). EPA must then set federal standards of performance for new sources within each listed source category. (CAA § 111(b)(1)(B)). Like section 112(d) standards, the standards for new sources under section 111(b) apply nationally and are effective upon promulgation. (CAA § 111(b)(1)(B)).

Existing sources are addressed under CAA section 111(d). EPA can issue standards of performance for existing sources in a source category only if it has established standards of performance for new sources in that same category under section 111(b), and only for certain

pollutants. (CAA § 111(d)(1)). Section 111(d) authorizes EPA to promulgate standards of performance that States must adopt through a SIP-like process, which requires State rulemaking action followed by review and approval of State plans by EPA. If a State fails to submit a satisfactory plan, EPA has the authority to prescribe a plan for the State. (CAA § 111(d)(2(A))). Below in this document we discuss in more detail (i) the applicable standards of performance for the regulatory requirements, (ii) the legal authority under 111(d) to regulate Hg from coal-fired Utility Units, and (iii) the legal authority to implement a cap-and-trade program for existing Utility Units.

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

1. What are the relevant Federal Register actions?

On December 20, 2000, EPA issued a finding pursuant to CAA section 112(n)(1)(A) that it was appropriate and necessary to regulate coal- and oil-fired Utility Units under section 112. In making this finding, EPA considered the Utility Study, which was completed and submitted to Congress in February 1998.

In December 2000, EPA concluded that the positive appropriate and necessary determination under section 112(n)(1)(A) constituted a decision to list coal- and oil-fired Utility Units on the section 112(c) source category list. Relying on CAA section 112(e)(4), EPA explained in its December 2000 finding that neither the appropriate and

necessary finding under section 112(n)(1)(A), nor the associated listing were subject to judicial review at that time. EPA did not add natural-gas fired units to the section 112(c) list in December 2000 because it did not make a positive appropriate and necessary finding for such units.

On January 30, 2004, EPA published in the Federal Register a proposed rule entitled "Proposed National Emissions Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units." In that rule, EPA proposed three alternative regulatory approaches. First, EPA proposed to retain the December 2000 Finding and associated listing of coal- and oil-fired Utility Units and to issue maximum achievable control technology-based (MACT) national emission standards for hazardous air pollutants (NESHAP) for such units. Second, EPA alternatively proposed revising the Agency's December 2000 Finding, removing coal and oil-fired Utility Units from the section 112(c) list,¹ and issuing final standards of performance under CAA section 111 for new and existing coal-fired units that emit Hg and new and existing oil-fired units that emit nickel (Ni). Finally, as a third alternative, EPA proposed retaining the December

¹ We did not propose revising the December 2000 finding for gas-fired Utility Units because EPA continues to believe that regulation of such units under section 112 is not appropriate and necessary. We therefore take no action today with regard to gas-fired Utility Units.

2000 finding and regulating Hg emissions from Utility Units under CAA section 112(n)(1)(A).

Shortly thereafter, on March 16, 2004, EPA published in the Federal Register a supplemental notice of proposed rulemaking entitled "Supplemental Notice of Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units." In that notice, EPA proposed certain additional regulatory text, which largely governed the proposed section 111 standards of performance for Hg, which included a cap-and-trade program. The supplemental notice also proposed State plan approvability criteria and a model cap-and-trade rule for Hg emissions from coal-fired Utility Units. The Agency received thousands of comments on the proposed rule and supplemental notice. Some of the more significant comments relating to today's action are addressed in this preamble. We respond to the other significant comments in the response to comments document entitled xxx, which is in the docket.

On December 1, 2004, EPA published in the Federal Register a notice of data availability entitled "Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources, Electric Utility Steam Generating Units: Notice of Data Availability." EPA

issued this notice: 1) to seek additional input on certain new data and information concerning Hg that the Agency received in response to the January 30, 2004 proposed rule and supplemental notice; and 2) to seek input on a revised proposed benefits methodology for assessing the benefits of Hg regulation. EPA conducts benefits analysis for rulemakings consistent with the provisions of Executive Order 12866.

2. How did the public participate in developing the final rule?

Upon signature on December 15, 2003, the proposed rule was posted on the Agency's Internet website for public review. Following publication of the notice of proposed rulemaking (NPR) in the Federal Register (69 FR 4652; January 30, 2004), a 60-day public comment period ensued. Concurrent public hearings were held in Research Triangle Park, NC, Philadelphia, PA, and Chicago, IL, on February 25 and 26, 2004, at which time any member of the public could provide oral comment on the NPR. On March 16, 2004, a supplemental notice of proposed rulemaking (SNPR) was published in the Federal Register (69 FR 12398). On March 17, 2004, EPA announced that the public comment period on the NPR and SNPR had been extended to April 30, 2004. A public hearing on the SNPR was held in Denver, CO, on March 31, 2004, during which time members of the public could provide oral comment on any aspect of the NPR or SNPR. On

May 5, 2004, EPA announced (69 FR 25052) that the public comment period for the NPR and SNPR had been reopened and extended until June 29, 2004. On December 1, 2004, EPA published a notice of data availability (NODA) with a public comment period until January 3, 2005 (69 FR 69864). In addition to the public comment process, EPA met with a number of stakeholder groups and has placed in the docket records of these meetings.

Although EPA defined in the various Federal Register notices distinct public comment periods for the NPR, SNPR, and NODA, the fact is that at no time from December 15, 2003, on has the EPA or the e-docket refused a public comment. Approximately 500,000 public comments were received during this period, indicating wide public interest and access.

C. What is the relationship between the final rule and the section 112 delisting action?

Elsewhere in today's Federal Register, EPA is publishing a final Agency action which delists Utility Units under section 112(n)(1)(A)/(c)(9). Today, EPA is revising the regulatory finding that it issued in December 2000 pursuant to CAA section 112(n)(1)(A), and based on that revision, removing coal-and oil-fired electric utility steam generating units ("coal- and oil-fired Utility Units") from the section 112(c) list. Section 112(n)(1)(A) of the CAA is the threshold statutory provision underlying this action.

Congress enacted this special provision for Utility Units which gives EPA considerable discretion in determining whether Utility Units should be regulated under section 112. The provision requires EPA to conduct a study to examine the hazards to public health that are reasonably anticipated to occur as the result of hazardous air pollutant ("HAP") emissions from electric utility steam generating units ("Utility Units") after imposition of the requirements of the CAA. The provision also provides that EPA shall regulate Utility Units under section 112, but only if the Administrator determines that such regulation is both "appropriate" and "necessary" considering, among other things, the results of the study. EPA completed the study in 1998 (the "Utility Study"), and in December 2000 found that it was "appropriate and necessary" to regulate coal-and oil-fired Utility Units under CAA section 112. That December 2000 finding focused primarily on Hg emissions from coal-fired Utility Units. In January 2004, EPA proposed revising the December 2000 appropriate and necessary finding and, based on that revision, removing coal- and oil-fired Utility Units from the section 112(c) list.

By today's action, we are revising the December 2000 appropriate and necessary finding and concluding that it is not appropriate and necessary to regulate coal- and oil-fired Utility Units under section 112. We are taking this action because we now believe that the December 2000 finding

lacked foundation and because recent information demonstrates that it is not appropriate or necessary to regulate coal- and oil-fired Utility Units under section 112. Based solely on the revised finding, we are removing coal- and oil-fired Utility Units from the section 112(c) list and instead establishing standards of performance for Hg for new and existing coal-fired Utility Units, as defined in CAA section 111.

The reasons supporting today's action are described in detail in a separate final Agency action published in this issue of the Federal Register.

D. What is the relationship between the final rule and other combustion rules?

Revised new source NSPS for SO₂, NO_x, and particulate matter (PM) were proposed under CAA section 111 for Utility Units (40 CFR part 60, subpart Da) and industrial boilers (IB) (40 CFR part 60, subpart Db) on February 28, 2005 (70 FR 9706). EPA earlier promulgated new-source NSPS for Utility Units (1979) and for IB (1987). In addition, the EPA has promulgated another combustion-related standard under CAA section 112: industrial, commercial, and institutional boilers and process heaters (40 CFR part 63, subpart DDDDD) on September 13, 2004 (69 FR 55218).

All of the rules pertain to sources that combust fossil fuels for electrical power, process operations, or heating. The applicability of these rules differ with respect to the

size of the unit (megawatts electric (MWe) or British thermal unit per hour (Btu/hr)) they regulate, the boiler/furnace technology they employ, or the portion of their electrical output (if any) for sale to any utility power distribution systems.

Any combustion unit that produces steam to serve a generator that produces electricity exclusively for industrial, commercial, or institutional purposes is considered an IB unit. A fossil-fuel-fired combustion unit that serves a generator that produces electricity for sale is not considered to be a Utility Unit under the final rule if its size is less than or equal to 25 MWe. Also, a cogeneration facility that sells electricity to any utility power distribution system equal to more than one-third of their potential electric output capacity and more than 25 MWe during any portion of a year is considered to be an electric utility steam generating unit.

Because of the similarities in the design and operational characteristics of the units that would be regulated by the different combustion rules, there are situations where coal-fired units potentially could be subject to multiple rules. An example of this situation would be cogeneration units that are covered under the proposed IB rule, potentially meeting the definition of a Utility Unit, and vice versa. This might occur where a decision is made to increase/decrease the proportion of

production output being supplied to the electric utility grid, thus causing the unit to exceed the IB/electric utility cogeneration criteria (i.e. greater than one-third of its potential output capacity and greater than 25 MWe). As discussed below, EPA has clarified the definitions and applicability provisions to lessen any confusion as to which rule a unit may be subject to.

II. Revision of Regulatory Finding on the Emissions of Hazardous Air Pollutants from Utility Units

A. What action is EPA taking today? (OGC)

B. Is it appropriate and necessary to regulate coal- and oil-fired Utility Units under section 112 based solely on emissions of non-Hg and non-Ni HAP? (OGC)

C. What effect does today's proposal have on the December 2000 decision to list coal- and oil-fired Utility Units under section 112(c)? (OGC)

III. Summary of the Final Rule Amendments

A. Who is subject to the final rule?

EPA is finalizing applicability provisions for subparts Da and HHHH that are consistent with historical applicability and definition determinations under the CAA section 111 and Acid Rain programs. EPA realizes that these definitions are somewhat different because of differences in the underlying statutory authority. EPA believes that it is appropriate to finalize the applicability and definitions of the revised subpart Da NSPS consistent with the historical

interpretations. Similarly, EPA believes that it is appropriate to finalize the applicability and definitions of subpart HHHH consistent with those of the Acid Rain and CAIR programs because of the similarities in their trading regimes.

The 40 CFR part 60, subpart Da NSPS apply to Utility Units capable of firing more than 73 megawatts (MW) (250 million Btu/hour) heat input of fossil fuel. The current NSPS also apply to industrial cogeneration facilities that sell more than 25 MW of electrical output and more than one-third of their potential output capacity to any utility power distribution system. Utility Units subject to revised subpart Da are also subject to subpart HHHH.

The following units in a State shall be Hg Budget units (i.e., units that are subject to the Hg Budget Trading Program), and any source that includes one or more such units shall be a Hg Budget source, subject to the requirements of subpart HHHH:

(a) Except as provided in paragraph (b), a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the start-up of a unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(b) For a unit that qualifies as a cogeneration unit starting on the date the unit first produces electricity, a cogeneration unit serving at any time a generator with

nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit that qualifies as a cogeneration unit starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this section starting on the day on which the unit first no longer qualifies as a cogeneration unit.

The Hg provisions of subparts Da and HHHH apply only to coal-fired Utility Units (i.e., units where any amount of coal or coal-derived fuel is used at any time). This is similar to the definition that is used in the Acid Rain Program to identify coal-fired units.

B. What are the primary sources of emissions, and what are the emissions?

The final rule amendments add Hg to the list of pollutants covered under 40 CFR part 60, subpart Da by establishing emission limits for new sources and guidelines for existing sources. New sources (and existing subpart Da facilities), however, remain subject to the applicable existing subpart Da emission limits for NO_x, SO₂, and PM.

C. What is the affected source?

Only those coal-fired Utility Units for which construction, modification, or reconstruction is commenced

after January 30, 2004, will be affected by the new-source provisions of the final rule amendments under CAA section 111(b). Coal-fired Utility Units existing on January 30, 2004, will be affected facilities for purposes of the CAA section 111(d) guidelines finalized in this action.

D. What are the emission limitations and work practice standards?

The following standards of performance for Hg are being finalized in today's action for new coal-fired 40 CFR part 60, subpart Da units:

Bituminous units:	0.0019 nanograms per joule (ng/J)(15 x 10 ⁻⁶ lb/megawatt-hour (MWh));
Subbituminous units:	0.0050 ng/J (38 x 10 ⁻⁶ lb/MWh);
Lignite units:	0.0102 ng/J (81 x 10 ⁻⁶ lb/MWh);
Coal refuse units:	0.00011 ng/J (0.9 x 10 ⁻⁶ lb/MWh);
IGCC units:	0.0025 ng/J (20 x 10 ⁻⁶ lb/MWh).

All of these standards are based on gross energy output.

In addition, to complying with these standards, new units, along with existing coal-fired Utility Units will be subject to the cap-and-trade provisions being finalized in today's action. The specifics of the cap are described

below.

Compliance with the final standards of performance for Hg will be on a 12-month rolling average basis, as explained below. This compliance period is appropriate given the nature of the health hazard presented by Hg.

E. What are the performance testing, initial compliance, and continuous compliance requirements?

Under 40 CFR subpart Da, new or reconstructed units must commence their initial performance test by the applicable date in 40 CFR 60.8(a). Because compliance with the Hg emission limits in 40 CFR 60.45a is on a 12-month rolling average basis, the initial performance test consists of 12 months of data collection with certified continuous monitoring systems, to determine the average Hg emission rate. New and existing units under Subpart HHHH must certify the required continuous monitoring systems and begin reporting Hg mass emissions data by the applicable compliance date in 40 CFR 60.4170(b).

Under 40 CFR 60.49a(s), the owner/operator is required to prepare a unit-specific monitoring plan and submit the plan to the Administrator for approval, no less than 45 days before commencing the certification tests of the continuous monitoring systems. The final rule amendments require that the plan address certain aspects with regard to the monitoring system; installation, performance and equipment specifications; performance evaluations; operation and

maintenance procedures; quality assurance techniques; and recordkeeping and reporting procedures. The final amendments requires all continuous monitoring systems to be certified prior to the commencement of the initial performance test.

Mercury emission limits. Compliance with the final standard of performance for Hg will be determined based on a rolling 12-month average calculation. The rolling average is weighted according to the number of hours of valid Hg emissions data collected each month, unless insufficient valid data are collected in the month, as explained below. The Hg emissions are determined by continuously collecting Hg emission data from each affected unit by installing and operating a continuous emission monitoring system (CEMS) or an appropriate long-term method (e.g., sorbent trap) that can collect an uninterrupted, continuous sample of the Hg in the flue gases emitted from the unit. The final rule amendments will allow the owner/operator to use any CEMS that meets the requirements in Performance Specification 12A (PS-12A), "Specifications and Test Procedures for Total Vapor-phase Mercury Continuous Monitoring Systems in Stationary Sources." Alternatively, a Hg concentration CEMS that meets the requirements of 40 CFR part 75, or a sorbent trap monitoring system that meets the requirements of 40 CFR 75.15 and 40 CFR part 75, Appendix K, may be used. Note that EPA has revised and renamed proposed Method 324,

"Determination of Vapor Phase Flue Gas Mercury Emissions from Stationary Sources Using Dry Sorbent Trap Sampling" as 40 CFR part 75, Appendix K).

For on-going quality assurance of the Hg CEMS, today's action requires the calibration drift and quarterly accuracy assessment procedures in 40 CFR part 60, Appendix F, to be implemented. The quarterly accuracy tests consist of a RATA and three measurement error tests (as described in PS 12-A), using HgCl₂ standards. In lieu of implementing the Appendix F procedures, the owner or operator may quality assure the data from the Hg CEMS according to 40 CFR part 75, Appendix B. For sorbent trap monitoring systems, an annual RATA is required, and the on-going quality assurance (QA) procedures of 40 CFR part 75, Appendix K, must be met.

The final rule requires valid Hg mass emissions data to be obtained for a minimum of 75 percent of the unit operating hours in each month. If this requirement is not met, the Hg data for the month are discarded. In each 12-month cycle, if there are any months in which the data capture requirement is not met, data substitution is required. For the first such occurrence, the mean Hg emission rate for the last 12 months is reported, and for any subsequent occurrences, the maximum emission rate from the past 12 months is reported. For any month in which a substitute Hg emission rate is reported, the substitute emission rate is weighted according to the number of unit

operating hours in that month when the 12-month rolling average is calculated.

For new cogeneration units, steam is also generated for process use. The energy content of this process steam must also be considered in determining compliance with the output-based standard. Therefore, the owner/operator of a new cogeneration unit will be required to calculate emission rates based on electrical output to the grid plus half the equivalent electrical output energy in the unit's process steam. The procedure for determining these Hg emission rates is described in 40 CFR 60.50a(g), and is consistent with those currently used in 40 CFR subpart Da.

The owner/operator of a new coal-fired unit that burns a blend of fuels will develop a unit-specific Hg emission limitation; the unit-specific Hg emission rate will be used for the portion of the compliance period in which the unit burned the blend of fuels. The procedure for determining the emission limitations is outlined in 40 CFR 60.45a(a)(5)(i). The owner/operator of an existing coal-fired unit that burns a blend of fuels will have to meet the limitations applicable under its unit-specific Hg allocation as outlined elsewhere in this action.

F. What are the notification, recordkeeping, and reporting requirements?

Today's action requires the owner or operator to maintain records of all information needed to demonstrate

compliance with the applicable Hg emission limit, including the results of performance tests, data from the continuous monitoring systems, fuel analyses, calculations used to assess compliance, and any other information specified in 40 CFR 60.7 (General Provisions).

Mercury compliance reports are required semiannually, under 40 CFR 60.51. Each compliance report must include the following information for each month of the reporting period: (1) the number of unit operating hours; (2) the number of unit operating hours with valid Hg emissions data; (3) the calculated monthly Hg emission rate; (4) the number of hours (if any) excluded from the emission calculations due to startup, shutdown and malfunction; (5) the 12-month rolling average Hg emission rate; and (6) the Appendix F data assessment report (DAR), or equivalent summary of QA test results if 40 CFR part 75 QA procedures are implemented.

IV. Significant Comments and Changes Since Proposal

A. Why is EPA not taking final action to regulate Ni emissions from oil-fired units?

In the January 30, 2004 proposal, EPA proposed to regulate Ni emissions from oil-fired units based on information collected and reported in the Utility Study. During the ensuing public comment period on the January 30, 2004, the March 2004, and December 2004 proposals, EPA received new information indicating that there were fewer

oil-fired units in operation and that Ni emissions had diminished since the Utility Study. Accordingly, in today's action, EPA is not taking final action on the proposal to regulate Ni emissions from oil-fired units.

B. How did EPA select the regulatory approach for coal-fired units for the final rule?

1. Applicability.

EPA is maintaining the discrete applicability definitions of "electric utility steam generating unit" that have historically been used under the CAA section 111 NSPS and the CAA section 401 Acid Rain programs.

As defined in 40 CFR 60.41a, an "electric utility steam generating unit" means

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

In the NPR, EPA proposed to modify the definition of an "electric utility steam generating unit" to mean

any fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered an electric utility steam generating unit.

This proposed change in the definition was made as a part of the proposed CAA section 112 rulemaking alternative; however, it was EPA's intent that this change also apply to the CAA section 111 rulemaking alternative and, therefore, EPA is finalizing it as part of the section 111 rule today.

Only Utility Units that are fired by coal in any amount, or combinations of fuels that include coal, are subject to the final rule. Integrated gasification combined cycle units are also subject to this final rule.

An affected source under NSPS is the equipment or collection of equipment to which the NSPS rule limitations or control technology is applicable. For the final rule, the affected source will be the group of coal-fired units at a facility (a contiguous plant site where one or more Utility Units are located). Each unit will consist of the combination of a furnace firing a boiler used to produce steam, which is in turn used for a steam-electric generator that produces electrical energy for sale. This definition of affected source will include a wide range of regulated units with varying process configurations and emission profile characteristics.

EPA received comment requesting clarification of the applicability definition relating to whether a unit would be classified as a Utility Unit or an IB. For the purposes of 40 CFR part 60, subpart Da, EPA believes that the definition being finalized today in 40 CFR part 60, subpart Da clearly

defines two categories of new sources - Utility Units and non-Utility Units (which could include IB units, etc.). That is, all three conditions must be met in order for a unit to be classified as a Utility Unit: (1) must sell more than 25 MWe to any utility power distribution system for sale; (2) any individual boiler must be capable of combusting more than 73 MW (250 million Btu/hr) heat input (which equates to 25 MWe on an output basis); and (3) if the unit is a cogeneration unit, it must sell more than one-third of its potential electric output capacity. The Agency's historical interpretation of the 40 CFR part 60, subpart Da definition has been that a boiler meeting the capacity definition (i.e., greater than 250 million Btu/hr) but connected to an electrical generator with a generation capacity of 25 MWe or less would still be classified as an "electric utility steam generating unit" under 40 CFR part 60, subpart Da. However, one or more new boilers with heat input capacities less than 250 million Btu/hr each but connected to an electrical generator with a generation capacity of greater than 25 MWe would not be considered Utility Units under 40 CFR part 60, subpart Da because they individually do not meet the definition (they would be considered IB).

Under the final 40 CFR part 60, subpart HHHH rule, EPA is continuing the definition of an Utility Unit used in the Acid Rain and CAIR trading programs. That is, any

cogeneration unit serving a generator with a nameplate capacity of greater than 25 MWe and supplying more than one-third potential electric output capacity and more than 25 MWe annually to any utility power distribution system for sale are Utility Units. These criteria are similar to the definition in the proposals with the clarification that the criteria be determined on an annual basis. These criteria are the same used in the CAIR and are similar to those used in the Acid Rain Program to determine whether a cogeneration unit is a Utility Unit and the NO_x SIP Call to determine whether a cogeneration unit is an Utility Unit or a non-Utility Unit.

2. Subcategorization.

Under CAA section 111(b)(2), the Administrator has the discretion to “. . . distinguish among classes, types, and sizes within categories of new sources . . .” in establishing standards when differences between given types of sources within a category lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques. At proposal, EPA examined a number of options for subcategorizing coal-fired Utility Units, including by coal rank and by process type. Based on the information available, EPA proposed to use five subcategories for establishing Hg limits based on a combination of coal rank and process type in this rule (bituminous coal,

subbituminous coal, lignite coal, coal refuse, and IGCC). EPA is today finalizing these five subcategories.

EPA received numerous comments both in support of and in opposition to the proposed subcategorization approach for both new and existing Utility Units. Those commenters opposed to the proposed approach suggested several alternative approaches, including no subcategorization, combining bituminous and subbituminous coal ranks in one subcategory, a separate subcategory for Gulf Coast lignite, and a separate subcategory for fluidized bed combustion (FBC) units, among others. Other commenters indicated that any subcategorization approach should be "fuel neutral," i.e., not disadvantage any rank of coal or lead to fuel switching, and/or should not result in the loss of viability of any coal rank.

Those commenters opposed to subcategorization generally argued that subcategorization can only be done on three criteria: class, type, and size of sources and contended that the fact that coal rank is one of the characteristics of a coal-fired boiler does not mean it can be used for subcategorization. The commenters stated that EPA's reliance on coal rank is misplaced because many coal-fired units blend or fire two or more ranks of coal in the same boiler and EPA itself states that coal blending is possible and not uncommon. The commenters stated that EPA had also provided unsupported claims that fuel switching would

require significant modification or retooling of a unit. The commenters cited case law to support their contention that EPA's proposed subcategorization is not permitted and stated that EPA's justification for rejecting a no subcategorization option is factually and legally indefensible.

A similar argument was presented by those commenters suggesting a single subcategory for bituminous and subbituminous coals. That is, given the extent of coal blending, particularly with respect to these two coal ranks, a single subcategory was appropriate. Further, the commenters argued that the proposed emission limits for the two subcategories disadvantaged bituminous coal.

Commenters representing producers and users of Gulf Coast lignite suggested that a separate subcategory should be established for this coal because of its significantly higher Hg content, even when compared to Fort Union lignite. Gulf Coast lignite, therefore, is more difficult to control.

Several commenters suggested that the ASTM classification methodology for ranking coals is an inappropriate basis upon which to base subcategorization. This claim was made primarily because of the overlaps in the ASTM classification methodology and the fact that some Western coal seams are alleged to provide both bituminous and subbituminous coal ranks. Reliance on the ASTM methodology would create problems for the users of this coal

in determining which subcategory they were in.

Several commenters indicated that a separate subcategory for FBC units, is appropriate because FBC units use a fundamentally different combustion process than pulverized-coal (PC) units, making them a different type of source.

Commenters concerned that the nation's fuel supply not be jeopardized stated that the final rule must be consistent with the need for reliable and affordable electric power, including affordable use of all coal ranks and options for efficient on-site power generation such as combined heat and power (CHP). The commenters stated that the final rule must facilitate - not discourage - the availability of an adequate and diverse fuel supply for the future, including all coal ranks, natural gas, nuclear energy, hydroelectric, and renewable sources. According to several commenters, the final rule must not aggravate the already precarious natural gas supply which is currently inadequate.

EPA continues to believe that it has the statutory authority to subcategorize based on coal rank and process type, as appropriate for a given standard. As initially structured, 40 CFR part 60, subpart Da subcategorized based on the sulfur content of the coal (essentially based on coal rank) for SO₂ emission limits and based on coal rank for NO_x emission limits. This approach was selected because of the differences in the relative ability of the respective

control technologies to effect emission reductions on the various coal ranks. Although EPA has recently proposed (February 28, 2005; 70 FR 9706) to change the format of the NO_x emission limits and to establish common SO₂ emission limits regardless of coal rank, we believe that the conditions existing when we proposed 40 CFR 60, subpart Da in 1978 (e.g., the inability of the technologies to control SO₂ and NO_x equally from all coal ranks) still exist for Hg and justify the use of subcategorization by coal rank for the Hg emission limits. At some point in the future, the performance of control technologies on Hg emissions could advance to the point that the rank of coal being fired is irrelevant to the level of Hg control that can be achieved (similar to the point reached by controls for SO₂ and NO_x emissions). If that occurs, EPA may consider adjusting the approach to Hg controls appropriately.

EPA believes that there are sufficient differences in the design and operation of utility boilers utilizing the different coal ranks to justify subcategorization by major coal rank. As documented in the record, utility boilers vary in size depending on the rank of coal burned (i.e., boilers designed to fire lignite coal are larger than those designed to fire subbituminous coal which, in turn, are larger than those designed to fire bituminous coal). Boilers designed to burn one fuel (e.g., lignite) cannot randomly or arbitrarily change fuels without extensive

testing and tuning of both the boiler and the control device. Further, if a different rank of coal is burned in a boiler designed for another rank, either in total or through blending, the practice is only done with ranks that have similar characteristics to those for which the boiler was originally designed. To do otherwise entails a loss of efficiency and/or increases in maintenance. That is, the ASTM classification system is structured on a continuum based on a number of characteristics (e.g., heat content or Btu value, fixed carbon, volatile matter, agglomerating vs. non-agglomerating) and provides basic information regarding combustion characteristics. Because more than one characteristic is used, the possibility exists for numerous situations where a coal could be "classified" in one rank based on one characteristic but in another rank based on another characteristic. Ranking is based on an evaluation of all characteristics. Therefore, it is possible that (for example) a non-agglomerating subbituminous coal with a heating value of 8,300 Btu/lb (ASTM classification III.3 - "Subbituminous C coal") could be co-fired with, or substituted for, a non-agglomerating lignite coal with heating value of 8,300 Btu/lb (ASTM classification IV.1 - "Lignite A coal"). This does not, however, mean that it is possible for a boiler designed to burn the Lignite A coal to burn an agglomerating coal with a heating value of 13,000 Btu/lb (e.g., ASTM classification II.5 - "High volatile C

bituminous coal"). Further, it does not mean that the substituted coal would exhibit the same "controllability" with respect to emissions reductions as the original coal, regardless of its compatibility with the boiler. The fact that a number of Utility Units co-fire different ranks of coal does not negate the overall differences in the ranks that preclude universal coal rank switching, particularly when the design coal ranks are not adjacent on the ASTM classification continuum.

Although other classification approaches have been suggested, the ASTM classification system remains the one most recognized and utilized by the industry and the one which the EPA believes is most suitable for use as a basis for subcategorization. Further, EPA is perplexed by the comments indicating that Utility Units do not know the coal rank that they are firing and would incur additional costs to determine this for the purpose of establishing their subcategory. Electric utilities are currently required by law to report to the U.S. Department of Energy, Energy Information Administration (DOE/EIA) on one or more of six different forms, the rank of coal burned in each Utility Unit. EPA is not suggesting that these utilities do anything different in establishing their subcategory and respective emission limit. Utility Units that blend coals from different ranks would need to follow the specified procedures for establishing the appropriate emission limit

for blended coals. EPA, therefore, believes that, at this time, coal rank is an appropriate and justifiable basis on which to subcategorize for the purposes of this rule.

EPA continues to believe that there is insufficient evidence available to justify separate subcategories for Gulf Coast and Fort Union lignites. The reanalysis of the data in support of the revised new-source NSPS Hg emission limits, discussed later in this preamble, incorporated data from units firing both types of lignite, further lessening the necessity of additional subcategorization. EPA will continue to evaluate the Hg emission data that become available, including that generated through the studies on emerging Hg control technologies by the DOE, and reassess issues of further subcategorizing lignites during the normal 8-year NSPS review cycle.

With regard to FBC units, EPA agrees that such units operate and are designed differently than conventional PC boilers. However, with the exception of FBC units firing coal refuse, there was no clear indication from the available data that such units influenced the ultimate Hg control. That is, in some cases, FBC units were better than most with respect to their Hg emissions; in other cases, FBC units were worse than most. Therefore, EPA concluded that it was the coal rank, rather than the process type (e.g., FBC, PC) that should govern in any determination relating to subcategorization.

EPA's modeling has shown minimal coal switching as a result of the final CAMR and CAIR actions. We believe that this rebuts the commenters' suggestions that today's final action will cause one or another coal rank to be "advantaged" or "disadvantaged" with respect to other coal ranks. Further, we do not believe that the final rules will have a negative impact on the nation's energy security, employment rates, or energy reliability.

New units designed to burn bituminous coals will still not be able to burn lignite coals (for example) and, thus, EPA believes that the need for subcategorization remains, even for new units.

C. How did the EPA determine the new source performance standards under section 111(b) for the final rule?

1. Criteria under section 111.

CAA section 111 creates a program for the establishment of "standards of performance." A "standard of performance" is "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction, which (taking into the cost of achieving such reduction, any nonair quality health and environmental impacts and energy requirements), the Administrator determines has been adequately demonstrated." CAA § 111(a)(1).

For new sources, EPA must first establish a list of

stationary source categories, which, the Administrator has determined "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." CAA § 111(b)(1)(A)). EPA must then set Federal standards of performance for new sources within each listed source category. (CAA § 111(b)(1)(B)). Like section 112(d) standards, the standards for new sources under section 111(b) apply nationally and are effective upon promulgation. (CAA § 111(b)(1)(B)).

Section 111(b) covers any category of sources that causes or contributes to air pollution that may reasonably be anticipated to endanger public health or welfare and provides EPA authority to regulate new sources of such air pollution. EPA included Utility Units on the section 111(b) list of stationary sources in 1979 and has issued final standards of performance for new Utility Units for pollutants, such as NO_x, PM, and SO₂. See 44 Fed. Reg. 33580; June 11, 1979; Subpart Da of 40 CFR Part 60. Nothing in the language of section 111(b) precludes EPA from issuing additional standards of performance for other pollutants, including HAP, emitted from new Utility Units. Moreover, nothing in section 112(n)(1)(A) suggests that Congress sought to preclude EPA from regulating Utility Units under section 111(b). Indeed, section 112(n)(1)(A) provides to the contrary, in that it calls for an analysis of utility HAP emissions "after imposition of the requirements" of the

CAA, which we have reasonably interpreted to mean those authorities that EPA reasonably anticipated at the time of the Study would have reduced utility HAP emissions.

2. Mercury control technologies.

At proposal, EPA stated that available information indicates that Hg emissions from coal-fired Utility Units are minimized in some cases through the use of PM controls (e.g., fabric filter or electrostatic precipitator (ESP)) coupled with a flue gas desulfurization (FGD) system. For bituminous-fired units, use of a selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR) system may further enhance Hg removal. This SCR-induced enhanced Hg removal appears to be absent for subbituminous- and lignite-fired units.

The EPA believes the best potential way of reducing Hg emissions from IGCC units is to remove Hg from the synthetic gas (syngas) before combustion. An existing industrial IGCC unit has demonstrated a process, using sulfur-impregnated activated carbon (AC) beds, that has proven to yield 90 to 95 percent Hg removal from the coal syngas. This technology could be adapted to the electric utility IGCC units and EPA believes this to be a viable option for new IGCC units.

In selecting a regulatory approach for formulating emission standards to limit Hg emissions from new coal-fired Utility Units, the performance of the control technologies discussed on Hg above were considered. The technical basis

(i.e., best demonstrated technology, BDT) selected for establishing Hg emission limits for new sources is the use of effective PM controls (e.g., fabric filter or ESP) and wet or dry FGD systems on subbituminous-, lignite-, and coal refuse-fired units; effective PM controls, wet or dry FGD systems, and SCR or SNCR on bituminous-fired units; and activated carbon beds for IGCC units.

EPA received several public comments that disagreed with the EPA's conclusion at proposal that Hg-specific controls for Utility Units, including activated carbon injection (ACI), will not be commercially available on a wide scale until 2010 or later. Arguments stated by these commenters included the following assertions: (a) Mercury control technologies are available now and EPA disregarded studies on emerging Hg control technologies by the DOE, the industry, and others. (b) The EPA's own numbers and other studies indicate that coal-fired plants can achieve 90 percent reduction regardless of the type of plant or coal. (c) Field testing of ACI has shown 90 percent capture of Hg. Units equipped with FGD units and fabric filters can obtain near 90 percent removal of Hg. (d) Studies indicate that the cost of Hg controls would be comparable to those for other pollutants and EPA disregarded these studies and the emerging state-of-the-art Hg control technologies. (e) Permits have been issued that will rely on sorbent injection technologies such as ACI (e.g., MidAmerican Energy, Council

Bluffs Unit 4, issued by IA; and Wisconsin Public Service Corporation, Weston Unit 4, issued by WI). These permits show that Hg removal technologies capable of achieving more than 80 percent control are available.

EPA agrees, based on the limited test data available, that some coal-fired units have exhibited greater than 90 percent Hg reductions during short-term sorbent injection studies. However, not all units have been able to achieve this level of control, even with similar control technologies installed. EPA disagrees with the commenters' assessment regarding the extent to which Hg-specific control technologies, including ACI, are currently available and on the time necessary for them to become commercially available. We do not believe that these technologies are available now for wide-spread or long-term usage. We have been following the studies of such technologies closely and have discussed their degree of development with vendors, the industry, and the DOE. With the exception of one test that has lasted approximately 1 year, no Utility Unit has operated a Hg-specific control technology full-scale for longer than approximately a month. Further, the technologies have not been fully evaluated on any coal ranks and have not even been evaluated under short-term conditions for some coal ranks (e.g., Gulf Coast lignite). In addition, other aspects of the use of Hg-specific control technologies (e.g., balance of plant, waste issues, other

atmospheric concerns) have not been fully addressed. Studies continue to (1) evaluate the impact of using both ACI and enhanced ACI (e.g., corrosion) on the coal-fired facility as a whole; (2) assess the impact of the ACI or enhanced ACI on the reuse and disposal of fly ash; and (3) evaluate the other atmospheric emissions and the impacts that may result from use of ACI or enhanced ACI (e.g., brominated dioxins emitted either directly or formed following emission to the atmosphere).

As discussed in the EPA Office of Research and Development's (ORD) revised White Paper (OAR-2002-0056-[XXXX]), since the release of the earlier White Paper (OAR-2002-0056-0463), additional data, mostly from short-term tests, have become available on Hg control approaches for Utility Units. Also, as noted above, the DOE and EPA have underway broad and aggressive research program, which will yield experience and data in the next few years.

Accordingly, EPA continues to believe that ACI and enhanced multipollutant controls will be available after 2010 for commercial application on most or all key combinations of coal rank and control technology to provide Hg removal levels between 60 and 90 percent on individual Utility Units. However, considering the progress made with halogenated activated carbon sorbents and other chemical injection approaches, it is now believed that optimized multipollutant controls may be available in the 2010 to 2015

timeframe for commercial application on most or all key combinations of coal rank and control technology to provide Hg removal levels between 90 and 95 percent on individual Utility Units. Such optimized controls could include use of sorbent (ACI or halogenated ACI) with enhanced SCR and/or enhanced FGD systems, and provide justification for a 2018 cap at a level below what is projected to be achieved from SO₂ and NO_x reduction levels alone.

Based on these tests, on-going studies, and discussions, we do not believe that the Hg-specific technologies have demonstrated an ability to consistently reduce Hg emissions by 90 percent (or any other level). We believe that the cap-and-trade approach selected for the final regulation is the best method for encouraging the continued development of these technologies. Further, although not ready for use in establishing a nationwide emission regulation, EPA believes that installation of Hg-specific control technologies, including ACI, on a limited number of units is possible well in advance of the Phase II cap. The economic incentives inherent to the two-phase cap-and-trade program finalized today will serve to advance the technologies such that they are widely available for use in compliance with the phase II cap.

3. Emissions limitations.

EPA established the proposed emission limits by direct transfer from the proposed new-source CAA section 112

emission limits. During the public comment period, it was pointed out by a number of commenters that under CAA section 111, NSPS should "reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction . . . (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements)" rather than "not be less stringent than the emission control that is achieved in practice by the best controlled similar source" under CAA section 112. The commenters pointed out that emission limits under both CAA sections begin with an assessment of what limit is achievable in practice with the best available controls, but the NSPS goes on to consider cost, energy use, and non-air impacts. Accordingly, it is inappropriate and inconsistent with the CAA for the EPA to establish an NSPS requirement based on an analysis undertaken pursuant to the requirements of CAA section 112. Commenters further noted that the proposed emission limits would preclude new coal-fired units from being built and offered approved permit levels as evidence that the proposed limits were unachievable.

EPA concurs with those commenters who indicated that the methodology on which the proposed new-source NSPS limits were based is not the only viable methodology for establishing such limits. We have, therefore, re-analyzed

the information collection request (ICR) data collected in 1999, and examined the Hg limits in recently issued permits. Based on this refined analysis, we have arrived at the following new-source NSPS Hg emission limits for the five subcategories:

Bituminous units:	0.0024 ng/J (19 x 10 ⁻⁶ MWh);
Subbituminous units:	0.0054 ng/J (41 x 10 ⁻⁶ lb/MWh);
Lignite units:	0.0175 ng/J (139 x 10 ⁻⁶ lb/MWh);
Coal refuse units:	0.00033 ng/J (2.7 x 10 ⁻⁶ lb/MWh);
IGCC units:	0.0025 ng/J (20 x 10 ⁻⁶ lb/MWh).

Documentation for this re-analysis may be found in the e-docket at OAR-2002-0056-XXXX.

To establish the revised new-source limits, EPA re-examined the 1999 ICR data which includes an estimate of the Hg removal efficiency for the suite of emission controls in use on each unit tested based on a comparison of the Hg concentration in the exhaust gas stream before and after the controls. The EPA focused primarily on the 1999 ICR data because it is the only test data for a large number of Utility Units employing a variety of control technologies currently available to the Agency and because there is very limited permit data for new or projected facilities from

which to determine existing Hg emission limits. (The EPA has historically relied on permit data in establishing new-source NSPS limits because it believes that such limits reasonably reflect the actual performance of the unit.) We analyzed the performance of currently installed control technologies in the respective subcategories in an effort to identify a best demonstrated control technology (BDT) for each subcategory. To do this, EPA ranked all of the units in each subcategory, from best performing to worst performing, based on their Hg removal efficiency. The EPA believes that using all of the available data, rather than just data from a smaller subset of units, is appropriate based on recognition of uncertainties associated with each subcategory (i.e., unit-to-unit variability, emission estimate variability, test method accuracy) and the limited number of data points in certain categories (e.g., coal refuse, IGCC and lignite). The EPA then used each unit's reported Hg control efficiency as a cut-off to determine the unit's representativeness for calculating the new source limits. That is, only units that appeared to be performing well were considered in determining the proper level of the new-source NSPS limit. For bituminous units, only units with reported control efficiencies above 85 percent were included. For subbituminous units and lignite units, only units with control efficiencies above 60 percent and 50 percent, respectively, were included in the analysis. The

control technology generally employed on the best performing bituminous units is a combination of a fabric filter (FF) and a spray dryer absorber (SDA). For the best performing subbituminous units, there is no single best performing system and, therefore, no BDT as such. Of the six best performing units, three units have FF and three units have an ESP. For the best performing lignite units, there is also no single best performing system. Of the three best performing units, one has FF/SDA combination, one has only a FF, and one has only an ESP.

To determine the appropriate achievable Hg emission level for each coal type, a statistical analysis was conducted. Specifically, the Hg emissions limitation achievable for a source at the 90th percentile confidence level using the one-sided z-statistics test (i.e., the emission limitation which a source with a given Hg removal efficiency, burning a coal with a specified Hg concentration is estimated to be able to achieve 90 percent of the time) was determined. The data used consisted of stack emission measurements (pounds Hg per trillion Btu, lb Hg/TBtu) for each unit, the average fuel Hg content for the fuel being burned by that unit during the test (parts per million, ppm), and the highest average monthly fuel Hg content reported for any unit in the best performing group of units. Since the Hg emissions from any control system is a linear function of the inlet Hg (i.e., Hg fuel content), assuming a

constant control efficiency, the reported test average for each unit was adjusted to determine the potential maximum Hg emissions that would be emitted if combusting a coal with the highest monthly average fuel Hg content reported for any of the best performing units in the subcategory. The calculated 90th percentile confidence limit for each subcategory, based on the calculated average Hg emissions, in lb Hg/TBtu, for the group of best performing units as a whole was determined to be the new source emission limit. Finally, the new source limit for IGCC units and its justification remains unchanged from the limit proposed in January 2004 (69 FR 4652).

EPA also evaluated recent, available permit Hg levels for comparison with the limits presented above. EPA does not believe that the use of permit Hg limits is appropriate for independently establishing new-source NSPS emission limits because of the limited number of permits issued with Hg emission levels and the limited experience of both State permitting authorities and the industry itself with establishing appropriate permit conditions. However, comparison of the available permit limits with those developed by EPA is a valid "reality check" on the appropriateness of EPA's limits. Available permits on bituminous-fired units have Hg emission limits ranging from approximately 2.0×10^{-5} lb/MWh to 3.9×10^{-5} lb/MWh; those for subbituminous-fired units range from 1.1×10^{-5} lb/MWh

to 12.6×10^{-5} lb/MWh. Considering the limited number of permits and the limited experience in developing appropriate Hg limits for those permits, EPA believes that its final new-source NSPS Hg emission limits are in reasonable agreement with these permits. Insufficient permit information is available to do a similar comparison for lignite- and coal refuse-fired units but we have used the same analytic procedure for these subcategories.

Further, EPA concurs with those commenters who indicated that we had overstated the variability in the context of the proposed CAA section 111 NSPS limits by using both a rigorous statistical analysis and a 12-month rolling average for compliance. Therefore, for the final rule, while we have retained the 12-month rolling average for compliance, we have used just the ICR data for the best performing units average to establish the NSPS limits. Given the favorable comparison with the available permit data, we believe that variability has been adequately addressed.

Although EPA has re-analyzed the available data and revised its new-source NSPS Hg emission limits, we continue to believe that these limits are of short-term value only. That is, the Hg cap being finalized today will be a greater long-term factor in constraining Hg emissions from new coal-fired Utility Units than will the new-source emission limits being issued today. In addition, the new source review

(NSR) provisions provide an additional constraint on new-source emissions, further diminishing the importance of the revised new-source Hg emission limits. Essentially, the new source limits become a "backstop" for the trading program and other NSR requirements.

C. How did the EPA determine the Hg cap-and-trade program under section 111(d) for the final rule?

1. Criteria under section 111 for standards of performance for existing sources.

[Placeholder]

2. What is the authority for cap-and-trade under section 111(d)?

Section 111(d)(1) authorizes EPA to promulgate regulations that establish a State Implementation Plan-like (SIP-like) procedure under which each State submits to EPA a plan that, under subparagraph (A), "establishes standards of performance for any existing source" for certain air pollutants, and which, under subparagraph (B), "provides for the implementation and enforcement of such standards of performance." Paragraph (1) continues, "Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." Section 111(a) defines, "(f)or purposes of...section (111),"

the term "standard of performance" to mean

a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Taken together, these provisions authorize EPA to promulgate a "standard of performance" that States must, through a SIP-like system, apply to existing sources. A "standard of performance" is defined as a rule that reflects emission limits to the degree achievable through "the best system of emission reduction" that EPA "determines has been adequately demonstrated," considering costs and other factors.

A cap-and-trade program reduces the overall amount of emissions by requiring sources to hold allowances to cover their emissions on a one-for-one basis; by limiting overall allowances so that they cannot exceed specified levels (the "cap"); and by reducing the cap to less than the amount of emissions actually emitted, or allowed to be emitted, at the start of the program. In addition, the cap may be reduced further over time. Authorizing the allowances to be traded maximizes the cost-effectiveness of the emissions reductions in accordance with market forces. Sources have an incentive to endeavor to reduce their emissions cost-effectively; if they can reduce emissions below the number of allowances they receive, they may then sell their excess allowances on the open market. On the other hand, sources have an

incentive to not put on controls that cost more than the allowances they may buy on the open market.

The term "standard of performance" is not explicitly defined to include or exclude an emissions cap and allowance trading program. In today's action, EPA proposes to interpret the term "standard of performance," as applied to existing sources, to include a cap-and-trade program. This interpretation is supported by a careful reading of the section 111(a) definition of the term, quoted above: A requirement for a cap-and-trade program (i) constitutes a "standard for emissions of air pollutants" (i.e., a rule for air emissions), (ii) "which reflects the degree of emission limitation achievable" (i.e., which requires an amount of emissions reductions that can be achieved), (iii) "through application of (a) ... system of emission reduction" (i.e., in this case, a cap-and-trade program that caps allowances at a level lower than current emissions).²²

Nor do any other provisions of section 111(d) indicate that the term "standard of performance" may not be defined

² The legislative history of the term, "standard of performance," does not address an allowance/trading system, but does indicate that Congress intended that existing sources be accorded flexibility in meeting the standards. See "Clean Air Act Amendments of 1977," Committee on Interstate and Foreign Commerce, H.R. Rep. No. 95-294 at 195, reprinted in 4 "A Legislative History of the Clean Air Act Amendments of 1977," Congressional Research Service, 2662. The EPA interprets this legislative history as generally supportive of interpreting "standard of performance" to include an allowance/trading program because such a program accords flexibility to sources.

to include a cap-and-trade program. Section 111(d)(1)(B) refers to the "implementation and enforcement of such standards of performance," and section 111(d)(1) refers to the State "in applying a standard of performance to any particular source," but all of these references readily accommodate a cap-and-trade program.

Although section 111(a) defines "standard of performance" for purposes of section 111, section 302(1) defines the same term, "(w)hen used in this Act," to mean "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." The term "continuous" is not defined in the CAA.

Even if the 302(1) definition applied to the term "standard of performance" as used in section 111(d)(1), EPA believes that a cap-and-trade program meets the definition. A cap-and-trade program with an overall cap set below current emissions is a "requirement of...emission reduction." Moreover, it is a requirement of "continuous" emissions reductions because all of a source's emissions must be covered by allowances sufficient to cover those emissions. That is, there is never a time when sources may emit without needing allowances to cover those emissions.³³

³ This interpretation of the term "continuous" is consistent with the legislative history of that term. See H.R. Rep. No. 95-294 at 92, reprinted in 4 Congressional research Service, A Legislative History of the Clean Air Act Amendments of 1977, 2559.

We note that EPA has on one prior occasion authorized emissions trading under section 111(d). (The Emission Guidelines and Compliance Times for Large Municipal Waste Combustors that are Constructed on or Before September 20, 1994; 40 CFR Part 60, subpart Cb.) This provision allows for a NO_x trading program implemented by individual States. Section 60.33b(C)(2) states,

A State plan may establish a program to allow owners or operators of municipal waste combustor plants to engage in trading of nitrogen oxides emission credits. A trading program must be approved by the Administrator before implementation.

Today's proposal is wholly consistent with this prior section 111(d) trading provision.

Having interpreted the term "standard of performance" to include a cap-and-trade program, EPA must next "determine" that such a system is "the best system of emissions reductions which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements)...has been adequately demonstrated." Section 111(a)(1). EPA has determined that a cap-and-trade program is the best system for reducing Hg emissions from coal-fired Utility Units.

Since the passage of the 1990 Amendments to the CAA, EPA has had significant experience with the cap-and-trade program for utilities. The 1990 Amendments provided, in Title IV, for the acid rain program, a national cap-and-trade program that covers SO₂ emissions from utilities.

Title IV requires sources to hold allowances for each ton of SO₂ emissions, on a one-for-one basis. EPA allocates the allowances for annual periods, in amounts initially determined by the statute, that decrease further at a statutorily specified time. This program has resulted in an annual reduction in SO₂ emissions from utilities from 15.9 million tons in 1990 (the year the Amendments were enacted) to 10.2 million tons in 2002 (the most recent year for which data is available). Emissions in 2002 were 9 percent lower than 2000 levels and 41 percent lower than 1980, despite a significant increase in electrical generation. As discussed elsewhere, at full implementation after 2010, emissions will be limited to 8.95 million tons, a 50 percent reduction from 1980 levels. The Acid Rain program allowed sources to trade allowances, thereby maximizing overall cost-effectiveness.

In addition, in the 1998 NO_x SIP Call rulemaking, EPA promulgated a NO_x reduction requirement that affects 21 States and the District of Columbia ("Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule," 63 FR 57,356 (October 27, 1998)). All of the affected jurisdictions are implementing the requirements through a cap-and-trade program for NO_x emissions primarily from utilities.⁴⁴ These

⁴ Non-electricity generating units are also included in the States' programs.

programs are contained in SIPs that EPA has approved; and EPA is administering the trading programs. However, for most States, the requirements did not need to be implemented until May, 2004.

The success of the Acid Rain cap-and-trade program for utility SO₂ emissions, which EPA duplicated in large measure with the NO_x SIP Call cap-and-trade program for, primarily, utility NO_x emissions, leads EPA to conclude that a cap-and-trade program for Hg emissions from utilities qualifies as the "best system of emission reductions" that "has been adequately demonstrated." A market system that employs a fixed tonnage limitation (or cap) for Hg sources from the power sector provides the greatest certainty that a specific level of emissions will be attained and maintained because a predetermined level of reductions is ensured. The EPA will administer a Hg trading program and will require the use of monitoring to allow both EPA and sources to track progress, ensure compliance, and provide credibility to the trading component of the program.

3. What is justification for the national Hg budget?

The EPA believes that a carefully designed "multi-pollutant" approach, a program designed to control NO_x, SO₂, and Hg at the same time (i.e., CAIR implemented with CAMR), is the most effective way to reduce emissions from the power sector. One key feature of such an approach is the interrelationship of the timing and cap levels for NO_x, SO₂,

and Hg. Our analyses show that the use of FGD (to reduce SO₂ emissions) and SCR (to reduce NO_x) also has the effect of controlling some level of Hg emissions at the same time. We have designed the CAIR and CAMR approach to take advantage of this so-called Hg "co-benefit." We believe, based on the results of sophisticated economic and environmental modeling analyses, that the Phase I Hg cap should be set at a level that reflects these co-benefits, and that additional controls designed specifically for Hg should not be required until after 2010. Furthermore, a multipollutant approach that focuses first on SO₂ and NO_x reductions will also achieve significant reductions in oxidized Hg. As explained elsewhere in this document, reductions in this Hg species are of the most beneficial to reductions in U.S. Hg deposition.

A phase-one cap based on "co-benefits" fulfills EPA's obligation to set a standard of performance based on the best system of emissions reduction that has been adequately demonstrated. Both DOE and ORD research currently indicate that Hg-specific air pollution control technology, most notably sorbent injection, may one day allow facilities to reliably reduce Hg emissions to levels significantly below the "co-benefits" levels achieved through application of SO₂ and NO_x control technologies. However, Hg-specific technologies such as ACI have not been demonstrated in practice on full-scale power plants for extended periods of

time, nor are they considered commercially available at this time. Moreover, current information on these technologies, as outlined in the ORD White Paper (OAR-2002-0056-[XXXX]) is not adequate for us to conclude that such technologies will be adequately demonstrated and commercially available before 2010. Therefore, for purposes of setting the 2010 Hg cap, we conclude that Hg reductions achieved as a "co-benefit" of controlling SO₂ and NO_x under CAIR should dictate the appropriate cap level. We find that requiring SO₂ and NO_x controls beyond those needed to meet the requirements of CAIR solely for purposes of further reducing Hg emissions by 2010 is not reasonable because the incremental cost effectiveness of such a requirement would be extraordinarily high. Furthermore, our analysis of engineering, financial, and other factors lead us to conclude under CAIR that a two-phased schedule was needed to allow the implementation of as much of the controls as feasible by an early date, with a later time for the remaining controls (see further discussion of this point below).

i. CAIR Phase I Requirements.

The CAIR-CAMR approach, which does not impose any Phase I Hg reduction requirements beyond those required to control SO₂ and NO_x emissions under Phase I of CAIR, sets the Phase I Hg emissions cap at 38 tpy. Thus, a cap of 38 tons reflects the co-benefits level and is established as a "hard cap" in this action.

In the final CAIR, EPA evaluated the amounts of SO₂ and NO_x emissions in upwind States that contribute significantly to downwind fine particle (PM_{2.5}) nonattainment, and the amounts of NO_x emissions in upwind States that contribute significantly to downwind ozone nonattainment. That is, EPA determined the amounts of emissions that must be eliminated to help downwind States achieve attainment, by applying highly cost-effective control measures to Utility Units and determining the emissions reductions that would result.

From past experience in examining multi-pollutant emissions trading programs for SO₂ and NO_x, EPA recognized that the air pollution control retrofits that result from a program to achieve highly cost-effective reductions are quite significant and can not be immediately installed. Such retrofits require a large pool of specialized labor resources, in particular, boilermakers, the availability of which will be a major limiting factor in the amount and timing of reductions.

EPA also recognized that the regulated industry will need to secure large amounts of capital to meet the control requirements while managing an already large debt load, and is facing other large capital requirements to improve the transmission system. Furthermore, allowing pollution control retrofits to be installed over time enables the industry to take advantage of planned outages at power plants (unplanned outages can lead to lost revenue and

adversely impact consumers) and to enable project management to learn from early installations how to deal with some of the engineering challenges that some plants/facilities/units pose, especially for the smaller units that often present space limitations. In addition, such phased installation of controls also minimizes any potential impact on the power grid and its stability and reliability.

In the final CAIR, EPA finalized a two-phased schedule for implementing the CAIR annual emission reduction requirements. The first phase includes two separate compliance deadlines: implementation of NO_x reductions are required by January 1, 2009 (covering 2009-2014) and that for SO₂ reductions by January 1, 2010 (covering 2010-2014). The EPA based its final rule, among other things, on its analysis of engineering, financial, and other factors that affect the timing for installing the emission controls that would be most cost-effective - and are therefore the most likely to be adopted - for States to meet the CAIR requirements. Those air pollution controls are primarily expected to be retrofitted FGD systems (scrubbers) for SO₂ and SCR systems for NO_x on coal-fired power plants.

The EPA's projections showed a significant number of affected sources installing these controls. The final two-phased schedule under CAIR allows the implementation of as much of the controls as feasible by an early date, with a later time for the remaining controls. The EPA has

performed several analyses to verify the adequacy of the available boilermaker labor for the installation of CAIR's Phase I controls. These analyses were not based just on using EPA's assumptions for the key factors affecting the boilermaker availability, but also on the assumptions suggested by commenters for these factors to determine the robustness of our key conclusions. See final CAIR preamble, section IV, for further discussion of this analysis and see CAMR docket for documents supporting this analysis.

ii. Availability of Hg Technology.

Additionally, EPA is setting a Hg emissions cap of 15 tpy in 2018 from coal-fired Utility Units. This cap reflects a level of Hg emissions reduction that exceeds the level that would be achieved solely as a co-benefit of controlling SO₂ and NO_x under CAIR. We conclude that this approach is warranted because we fully expect Hg-specific air pollution control technologies such as ACI to have been adequately demonstrated and commercially available, sufficiently before 2018 to allow for their deployment across the field of units to comply with the Phase II cap in 2018. This conclusion relies on the fact that the current-day pilot scale ACI projects at power plants should yield information that ought to be usable in implementing similar pilot scale projects at other facilities. Data from all of these pilot studies ultimately should allow companies to design full scale applications that should provide

reasonable assurance that emissions limitations can be reliably achieved over extended compliance periods. We do not believe that such full scale technologies can be developed and widely implemented within the next 5 years; however, it is reasonable to assume that this can be accomplished over the next 13 years.

iii. Utility Mercury Emission Reductions Expected as Co-Benefits From CAIR

The final CAIR requires annual SO₂ and NO_x reductions in 23 States and the District of Columbia, and also requires ozone season NO_x reductions in 25 States and the District of Columbia. Many of the CAIR States are affected by both the annual SO₂ and NO_x reduction requirements and the ozone season NO_x requirements. CAIR was designed to achieve significant emissions reductions of SO₂ and NO_x in a highly cost-effective manner to reduce the transport of fine particles that have been found to contribute to nonattainment. EPA analysis has found that the most efficient method to achieve the emissions reduction targets is through a cap-and-trade system on the power sector that States have the option of adopting. In fact, States may choose not to participate in the optional cap-and-trade program and may choose to obtain equivalent emissions reductions from other sectors. However, EPA believes that a region-wide cap-and-trade system for the power sector is the best approach for reducing emissions. The power sector

accounted for 67 percent of nationwide SO₂ emissions and 22 percent of nationwide NO_x emissions in 2002.

EPA expects that States will choose to implement the final CAIR program in much the same way they chose to implement their requirements under the NO_x SIP Call. As noted above, under the NO_x SIP Call, EPA gave States ozone season NO_x reduction requirements and the option of participating in cap-and-trade program. In the final rulemaking, EPA analysis indicated that the most cost-efficient method to achieve reductions targets would be through a cap-and-trade program. Each affected State, in its approved SIP, chose to control emissions from Utility Units and to participate in the cap-and-trade program.

Therefore, EPA anticipates that States will comply with CAIR by controlling Utility Unit SO₂ and NO_x emissions. Further, EPA anticipates that States will implement those reductions through the cap-and-trade approach, because the power sector represents the majority of national SO₂ emissions and the majority of stationary NO_x emissions, and represents highly cost-effective sources of reductions of SO₂ and NO_x (for further discussion of cost-effectiveness, see section IV of Final CAIR preamble). EPA modeled a region-wide cap-and-trade system for the power sector in the States covered by CAIR, and this modeling projected that most reductions in NO_x and SO₂ would come through the installation of scrubbers, for SO₂ control, and SCR, for NO_x

control (see Regulatory Impact Assessment for CAIR and CAMR in docket). Scrubbers and SCR are proven technologies for controlling SO₂ and NO_x emissions and sources have installed them to comply with the Acid Rain trading program and the NO_x SIP Call trading program. EPA's modeling also projected that the installation of these controls would also achieve Hg emission reductions as a co-benefit.

EPA projections of Hg co-benefits are based on 1999 Hg ICR emission test data and other more recent testing conducted by EPA, DOE, and industry participants (for further discussion see *Control of Emissions from Coal-Fired Electric Utility Boilers: An Update*, EPA/Office of Research and Development, March 2005, in docket). That emissions testing has provided a better understanding of Hg emissions from Utility Units and their capture in pollution control devices. Mercury speciates into three basic forms, ionic, elemental, and particulate (particulate represents a small portion of total emissions). Ionic, or non-elemental, Hg compounds are the most important from a near-field deposition stand-point. In general, ionic Hg compounds are more readily controlled (because they tend to be water soluble) than is elemental Hg and the presence of chlorine compounds (which tend to be higher for bituminous coals) results in increased ionic Hg. Overall the 1999 Hg ICR data revealed higher levels of Hg capture for bituminous coal-fired plants as compared to subbituminous and lignite

coal-fired plants and a significant capture of ionic Hg in wet-FGD scrubbers. Additional Hg testing indicates that for bituminous coals SCR has the ability to convert elemental Hg to ionic Hg and thus allow easier capture in a wet-FGD scrubber. This understanding of Hg capture was incorporated into EPA modeling assumptions and is the basis for our projections of Hg co-benefits from installation of scrubbers and SCR under CAIR.

Given the history of the Acid Rain and NO_x SIP Call trading programs, EPA anticipates that reductions in SO₂ emissions will begin to occur before 2010 (limited to a degree by the time and resources needed to install control technologies) because of the ability to bank SO₂ emission allowances. Companies have an incentive to achieve greater and faster SO₂ reductions than needed to meet the current Acid Rain cap because the excess allowances they generate can be "banked" and either later sold on the market or used to demonstrate compliance in 2010 and beyond at the facility that generated the excess allowances. Based on the analysis of CAIR, EPA's modeling projects that Hg emissions would be 38.0 tons (12 tons of non-elemental Hg) in 2010, 34.4 tons in 2015 (10 tons of non-elemental Hg), and 34.0 tons in 2020 (9 tons of non-elemental Hg), about a 20 and 30 percent reduction (in 2010 and 2015, respectively) from a 1999 baseline of 48 tons. For further discussion of EPA modeling results and projected emissions see Chapter 8 of the

Regulatory Impact Assessment.

iv. CAMR Reductions Requirements in 2018.

As discussed above, EPA is setting a cap of 15 tons in 2018 for coal-fired Utility Units. EPA projected future Hg emissions from the power generation sector using the Integrated Planning Model (IPM). The EPA uses IPM to analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous States and the District of Columbia. IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. The EPA used IPM to project both the national level and the unit level of utility unit Hg emissions under different control scenarios. The EPA also used IPM to project the costs of those controls.

In these IPM runs, EPA assumed that States would implement the Hg requirements through the Hg cap and trade program that EPA is establishing in today's rulemaking. The cap-and-trade program is implemented in two phases, with a hard cap of 38 tons in 2010 (set at the co-benefits reduction under CAIR) and 15 tons in 2018. EPA modeling of section 111 projects banking of allowances due to excess Hg reductions in the 2010 to 2017 timeframe for compliance with the cap in 2018 and beyond timeframe. A cap-and-trade program assures that those reductions will be achieved with the least cost. For that reason, EPA believes it reasonable to assume that States will adopt the program even though

they are not required to do so.

As discussed above, under the CAIR scenario modeled by EPA, SO₂ and NO_x emission reductions (and Hg co-benefit reductions) are projected to result from the installation of additional FGD and additional SCR units on existing coal-fired generation capacity. Under the CAMR scenario modeled by EPA, units are projected to install SCR and scrubbers to meet their SO₂ and NO_x requirements and take additional steps to address the remaining Hg reduction requirements under section 111, including adding Hg-specific control technologies (model applies ACI), additional scrubbers and SCR, dispatch changes, and coal switching. Many of these reductions are projected to result from large units installing controls and selling excess allowances. Under the cap-and-trade approach we are projecting that Hg reductions result from units that are most cost effective to control, which enables those units that are not cost effective to install controls to use other approaches for compliance including buying allowances, switching fuels, or making dispatch changes.

Based on the analysis of CAMR, EPA's modeling projects that Hg emissions would be 31.3 tons in 2010, 27.9 tons in 2015, and 24.3 tons in 2020, about a 35 percent reduction in 2010, about 42 percent reduction in 2015, and about 50 percent reduction in 2020 from a 1999 baseline of 48 tons. For further discussion of EPA modeling results and projected

emissions see Chapter 8 of the Regulatory Impact Assessment. EPA is not requiring further reductions by 2015, beyond the CAIR phase I cap co-benefits, and therefore, we are not adjusting Hg allowances downward beginning in 2015, rather adjusting allowances in 2018. EPA maintains that it is not necessary for the 2015 Hg cap to mirror the Hg co-benefits achieved in CAIR phase II cap because: (1) these co-benefits would result automatically from the need to meet SO₂ and NO_x caps; the market will assure that the Hg reductions will occur; and (2) in 2018, the lower cap takes into account the reduced Hg emissions resulting from CAIR phase II implementation. As we can see from the CAMR analysis, 2015 Hg emissions are projected to be substantially below the co-benefits projections under CAIR (34 tons in 2015). Thus, EPA maintains that it is not necessary to have the 2015 Hg cap mirror the Hg co-benefits achieved in CAIR phase II cap because the 2018 cap ensures those reductions.

v. Cost-effectiveness of the Hg cap in 2018.

As discussed above under CAMR, EPA projected future Hg emissions and the cost of those controls from the power generation sector using the IPM. In these IPM runs, EPA assumed that States would implement the Hg requirements through the Hg cap-and-trade program that EPA is establishing in today's action.

The 15-ton cap in 2018 is supported by cost

considerations and the sophisticated economic modeling completed in support of the CAIR and CAMR regulations. This modeling shows that the 15-ton Phase II cap will, in fact, require Hg-specific controls to be installed on certain Utility Units; however, such controls should not have any significant impact on power availability, reliability, or pricing to consumers. Moreover, our models predict that a 15-ton cap would not cause any significant shift in the fuels currently utilized by power plants or in the source of these fuels. For further discussion of EPA modeling results and projected costs see Chapter 8 of the Regulatory Impact Assessment.

4. State and Tribal Emissions Reductions Requirements.

The EPA below also outlines a method for apportioning the nation-wide budget to individual States and Tribes. The EPA maintains that the emission budget provides an efficient method for achieving necessary reductions in Hg emissions (as described in earlier sections of this preamble), while providing substantial flexibility in implementing the program.

i. Geographic scope of trading program.

Today's proposal will apply to all coal-fired Utility Units located in all 50 States of the U.S., as well as those located on Tribal lands. As discussed further below, each State and Tribe has been assigned a Statewide emissions budget for Hg. Each of these States must submit a State

Plan revision detailing the controls that will be implemented to meet its specified budget for reductions from electric generating units. Therefore, should some States choose to achieve the mandated reductions by using an approach other than the proposed emissions trading rule, the geographic scope of the trading program would not be nationwide. Tribes that have coal-fired Utility Units that will be affected by this rule on their land also have been assigned a Hg emission budget. Tribes will be responsible for submitting a Tribal implementation plan (TIP) analogous to the State Plans discussed throughout this preamble, and, like States, can chose to adopt the Model Cap-and-Trade Rule described elsewhere in this action.

ii. State and Tribal emission budgets.

Each of the States and Tribes and the District of Columbia covered by today's final rule has been assigned a State or Tribal emissions budget for Hg. As discussed in detail below, these budgets were developed by totaling unit-level emissions reductions requirements for coal-fired electricity generating devices. States have the flexibility to meet these State budgets by participating in a trading program or establishing another methodology for Hg emissions reductions from coal-fired electric generating units, as discussed elsewhere in this action. States have the ability to require reductions beyond those required by the state budget. The State and Tribal emission budgets are a

permanent cap regardless of growth in the electric sector and, therefore, States and Tribes have the responsibility of incorporating new units in their Hg emission budgets.

As proposed in the NPR and SNPR, EPA is finalizing a formula for determining the total amount of emissions for the Budget Trading Program for each specific State or Tribe using that same mechanism, finalizing the amount of emissions for the Program within each State for 2010 and 2018. That formula is the sum of the weighted shares for each affected Utility Unit in the State or Tribe, based on the proportionate share of their baseline heat input, adjusted to reflect the ranks of coal combusted by the unit during the baseline period, to total heat input of all affected units. As discussed further below, EPA is finalizing adjustment factors of 1 for bituminous, 1.25 for subbituminous, and 3 for lignite coals.

As discussed elsewhere in this preamble, new sources will comply with NSPS for Hg. In addition, as proposed in the NPR and SNPR, new sources will be covered under the Hg cap of the trading program, and will be required to hold allowances equal to their emissions. As discussed under the model cap-and-trade program, EPA is also finalizing in the example allocation methodology in the model cap-and-trade program whereby these new sources do not receive an adjustment to their allocated share of the allowances (that reflects the rank of coal combusted).

iii. Rationale for unit-level allowances.

Different ranks of coal may achieve different Hg reductions depending on the control equipment installed at the unit. In order to develop State and Tribal emissions budgets from unit allocations, EPA proposed that allowances would be distributed to States based on their share of total heat input. These allocations were then adjusted to reflect the concern that the installation of PM, NO_x, and SO₂ control equipment on different coal ranks results in different Hg removal.

In the NPR and SNPR, for purposes of this hypothetical allocation of allowances, EPA proposed that each unit's baseline heat input is adjusted to reflect the ranks of coal combusted by the unit during the baseline period. Adjustment factors of 1 for bituminous, 1.25 for subbituminous, and 3 for lignite coals were proposed in the NPR. Alternatively, for purposes of this hypothetical calculation of State budgets, EPA took comment on using adjustment factors based on the MACT emission rates proposed in the NPR and the proportionate share of their baseline heat input to total heat input of all affected units.

Several commenters supported the proposed adjustment factors of 1 for bituminous, 1.25 for subbituminous, and 3 for lignite coals. Many commenters supported revisions to the adjustment factors, including a factor of 1.5 for subbituminous. Several other commenters supported the use

of no adjustment factors. Although supporting the use of multipliers for the coal ranks, some commenters argued that EPA should provide more scientific basis for the adjustment factors and recommended at minimum using adjustment factors based on the MACT approach.

For today's action, EPA is finalizing adjustment factors of 1 for bituminous, 1.25 for subbituminous, and 3 for lignite coals based on the expectation that Hg in the coal ranks reacts differently to NO_x and SO₂ control equipment and that the heat input of the different coal ranks varies. The conclusion that Hg in each of the coals reacts differently to NO_x and SO₂ control equipment was based on information collected in the ICR as well as more recent data collected by EPA, DOE, and industry sources. This information, which was collected from units of various coal ranks and control equipment configuration, indicated differing levels of Hg removal. The test data indicated that installation of PM, NO_x, and SO₂ controls on plants burning bituminous coals resulted in greater Hg reduction on average than plants burning subbituminous coals or lignite coals. Likewise, the test data indicated that installation of PM, NO_x, and SO₂ controls on plants burning subbituminous coals resulted in somewhat greater Hg removal than plants burning lignite coals. On average, units burning lignite coal showed the least Hg removal of the three coal ranks. Further discussion of these adjustment factors can be found

in the docket. **[add cite for Hg Budget TSD]**

These adjustment factors are considered to be reasonable based on the test data currently available. Although, we realize that these factors do not in all cases accurately predict relative rates of Hg emissions from Utility Units with NO_x and SO₂ controls, the values we have assigned to the factors will succeed in equitably distributing allowances to the States and Tribes on the basis of the affected industry within their borders. As discussed in the model cap-and-trade program, EPA is finalizing under the example allocation methodology that allocations by States to new sources will not be adjusted by coal type.

iv. Distribution of State and Tribal budgets.

The trading program establishes a cap on Hg emissions for affected electric generating units of 38 tpy starting in 2010 and 15 tpy in 2018. The unit-level emission allocations are the basis for establishing State and Tribal emission budgets with the State budgets equaling the total of the individual unit emission limits in a given State (see Table 1 below). States also have the flexibility to not participate in the trading program or require more stringent Hg emissions reductions. For States that do not participate in the trading program, States can establish their own methodology for meeting State Hg budgets by reductions from affected Utility Units. As proposed in the NPR and SNPR,

EPA is finalizing the requirement that new coal-fired Utility Units will be subject to the State Hg emission cap. State and Tribal budgets remain the same after the inclusion of new units and States and Tribes have the responsibility of addressing new units in their respective emission budgets.

EPA received comments from Tribes noting that only States currently receive allowances under the proposal, despite unit allocations being made to Tribal sources, and requesting that Tribes be accommodated into the cap-and-trade program. Because under CAA authority Tribes have jurisdiction over sources on Tribal land, EPA agrees with the commenters that these Tribal sources need to be included in the cap-and-trade program and the final CAMR establishes Tribal budgets for existing Tribal sources.

In the final rule, EPA is establishing two Tribal budgets for three existing coal-fired Utility Units on Tribal lands. These are Navajo Generating Station (Salt River Project; Page, AZ), Bonanza Power Plant (Deseret Generation and Transmission Cooperative; Vernal, UT), and Four Corners Power Plant (Salt River Project/Arizona Public Service; Fruitland, NM). Navajo Generating Station and Four Corners Power Plant are on lands belonging to Navajo Nation, and Bonanza Power Plant is located on the Uintah and Ouray Reservation of the Ute Indian Tribe. Therefore, in addition to the 50 State budgets, this final rule also contains

budgets for the Navajo and Ute Indian Tribes. Tribal budgets are calculated using the same methodology as State budgets. In the proposed rule, these three units on Tribal lands were included in the State budgets for Arizona, Utah, and New Mexico. The emissions budgets for today's final rule for Arizona, Utah, and New Mexico are adjusted to reflect the movement of sources to Tribal emission budgets.

For Tribal lands that do not currently have any coal-fired electricity generation, EPA intends to address any future planned construction of coal-fired Utility Units on Tribal lands on a case-by-case basis, by working with the relevant Tribal government to regulate the Utility Units through either a Tribal implementation plan (TIP) or Federal implementation plan (FIP). This is the same approach that is taken in the CAIR. EPA does not believe there is sufficient information to design Tribal allocation provisions for new generation at this time. Therefore, rather than create a Federal allowance set-aside for Tribes, the EPA will work with Tribes and potentially affected States to address concerns regarding the equity of allowance allocations on a case-by-case basis as the need arises. The EPA may choose to revisit this issue through a separate rulemaking in the future.

In the SNPR, because three States and the District of Columbia have no coal-fired Utility Units, EPA proposed Hg emission budgets of zero tons for three States (Idaho, Rhode

Island, and Vermont) and the District of Columbia. EPA did not receive adverse comments from these States on their proposed budgets and is finalizing Hg emission budgets of zero tons for three States (Idaho, Rhode Island, and Vermont) and the District of Columbia. If these States or the District of Columbia participate in the CAMR trading program, new coal-fired Utility Units will be required to hold allowances equal to their emissions. As participants in the cap-and-trade program, these sources could buy allowances and meet their requirements. This is similar to situation that new units face under the existing Acid Rain Program. The final State and Tribal Hg emission budgets are presented in Table 1.

Table 1. State Hg emission budgets.

State	Budget (tons)	
	2010-2017	2018 and thereafter
Alaska	0.005	0.002
Alabama	1.289	0.509
Arkansas	0.516	0.204
Arizona	0.454	0.179
California	0.041	0.016
Colorado	0.706	0.279
Connecticut	0.053	0.021
Delaware	0.072	0.028
District of Columbia	0	0
Florida	1.233	0.487
Georgia	1.227	0.484
Hawaii	0.024	0.009
Idaho	0	0
Iowa	0.727	0.287
Illinois	1.594	0.629
Indiana	2.098	0.828
Kansas	0.723	0.285
Kentucky	1.525	0.602
Louisiana	0.601	0.237
Massachusetts	0.172	0.068

Maryland	0.49	0.193
Maine	0.001	0.001
Michigan	1.303	0.514
Minnesota	0.695	0.274
Missouri	1.393	0.55
Mississippi	0.291	0.115
Montana	0.378	0.149
Navajo Nation	0.601	0.237
North Carolina	1.133	0.447
North Dakota	1.564	0.617
Nebraska	0.421	0.166
New Hampshire	0.063	0.025
New Jersey	0.153	0.06
New Mexico	0.299	0.118
Nevada	0.285	0.112
New York	0.393	0.155
Ohio	2.056	0.812
Oklahoma	0.721	0.285
Oregon	0.076	0.03
Pennsylvania	1.78	0.702
Rhode Island	0	0
South Carolina	0.58	0.229
South Dakota	0.072	0.029
Tennessee	0.944	0.373
Texas	4.657	1.838
Utah	0.506	0.2
Ute Indian Tribe	0.06	0.024
Virginia	0.592	0.234
Vermont	0	0
Washington	0.198	0.078
Wisconsin	0.89	0.351
West Virginia	1.394	0.55
Wyoming	0.952	0.376

D. CAMR Model Cap-and-Trade Program

1. What Is the Overall Structure of the Model Hg Cap-and-Trade Program?

EPA is finalizing model rules for the CAMR Hg trading program that States can use to meet the emission reduction requirements in the CAMR. These rules are designed to be referenced by States in State rulemaking. State use of the model cap-and-trade rules helps to ensure consistency between the State programs, which is necessary for the

market aspects of the trading program to function properly. Although not as effective as a legislated program such as the President's Clear Skies legislation, this does allow the CAMR program to build on some of the successful Acid Rain Program. Consistency in the CAMR requirements from State-to-State benefits the affected sources, as well as EPA which administers the program on behalf of States.

This section focuses on the structure which adds a model rule for the CAMR in 40 CFR part 60, subpart HHHH. Commenters (who supported the cap-an-trade approach) generally supported the proposed structure of the model rule, which is maintained in the final rule. Later sections of today's rule discuss specific aspects of the model rule that have been modified or maintained in response to comment.

The model rules rely on the detailed unit-level emissions monitoring and reporting procedures of 40 CFR part 75 and consistent allowance management practices. (Note that full CAMR-related State Plan requirements, i.e., 40 CFR part 60, are discussed elsewhere in this action.) Additionally, a discussion of the final revisions to parts 72 through 77 in order to, among other things, facilitate the interaction of the title IV Acid Rain Program's SO₂ cap-and-trade provisions and those of the CAMR Hg trading program is provided elsewhere in this action.

i. Road map of model cap-and-trade rule.

The following is a brief "road map" to the final CAMR cap-and-trade program and is provided as a convenience to the reader. Please refer to the detailed discussions of the CAMR programmatic elements throughout today's rule for further information on each aspect.

State Participation:

- States may elect to participate in an EPA-managed cap-and-trade program for coal-fired Utility Units greater than 25 MW. To participate, a State must adopt the model cap-and-trade rules finalized in this section of today's rule with flexibility to modify sections regarding source Hg allocations.
- For States that elect not to participate in an EPA-managed cap-and-trade program, their respective State Hg budgets will serve as a firm cap.

Emission Allowances:

- The CAMR cap-and-trade program will rely upon CAMR annual Hg allowances allocated by the States.

Allocation of Allowances to Sources:

- Hg allowances will be allocated based upon the States chosen allocation methodology. EPA's model Hg rule has provided an example allocation, complete with regulatory text, that may be used by States or replaced by text that implements a States alternative allocation methodology.

Emission Monitoring and Reporting by Sources:

- Sources monitor and report their emissions using 40 CFR part 75.
- Source information management, emissions data reporting, and allowance trading is done through on-line systems similar to those currently used for the Acid Rain SO₂ and NO_x SIP Call programs.

Compliance and Penalties:

- For the Hg cap-and-trade program, any source found to have excess emissions must: (1) surrender allowances sufficient to offset the excess emissions; and, (2) surrender allowances from the next control period equal to three times the excess emissions.

ii. Comments regarding the use of a cap-and-trade approach and the proposed structure.

As discussed elsewhere in this action, many commenters did not support the cap-and-trade approach. For the many commenters, however, that did support the cap-and-trade approach, they also supported EPA's overall framework of the model rule to achieve the mandated emission reductions.

Many commenters supported states having the flexibility to achieve emissions reductions however they chose, including developing their own cap-and-trade program or choosing not to participate. Other commenters did not support giving the states flexibility to participate in the program and

supported requiring their participation, including imposing a uniform national allocation scheme. (Note that comments on specific mechanisms within the cap-and-trade program are discussed in the topic-specific sections that follow.)

2. What Is the Process for States to Adopt the Model Cap-and-trade Program and How Will it Interact with Existing Programs?

i. Adopting the Hg model cap-and-trade program.

States may choose to participate in the EPA-administered cap-and-trade program, which is a fully approvable control strategy for achieving all of the emissions reductions required under today's rulemaking in a more cost-effective manner than other control strategies. States may simply reference the model rules in their State rules and, thereby, comply with the requirements for Statewide budget demonstrations detailed elsewhere in this action. Specifically, States can adopt the Hg cap-and-trade program whether by incorporating by reference the CAMR cap-and-trade rule (part 60 subpart HHHH) or codifying the provisions of the CAMR cap-and-trade rule, in order to participate in the EPA-administered Hg cap-and-trade program.

As proposed, EPA is requiring States that wish to participate in the EPA-managed cap-and-trade program to use the model rule to ensure that all participating sources, regardless of which State they are located, are subject to

the same trading and allowance holding requirements. Further, requiring States to use the complete model rule provides for accurate, certain, and consistent quantification of emissions. Because emissions quantification is the basis for applying the emissions authorization provided by each allowance and emissions authorizations (in the form of allowances) are the valuable commodity traded in the market, the emissions quantification requirements of the model rule are necessary to maintain the integrity of the cap-and-trade approach of the program and therefore to ensure that the environmental goals of the program are met.

ii. Flexibility in adopting Hg model cap-and-trade rule.

It is important to have consistency on a State-to-State basis with the basic requirements of the cap-and-trade approach when implementing a multi-State cap-and-trade program. Such consistency ensures the: preservation of the integrity of the cap-and-trade approach so that the required emissions reductions are achieved; smooth and efficient operation of the trading market and infrastructure across all States so that compliance and administrative costs are minimized; and equitable treatment of owners and operators of regulated sources. However, EPA believes that some differences are possible without jeopardizing the environmental and other goals of the program. Therefore, the final rule allows States to modify the model rule

language to best suit their unique circumstances with regard to allocation methodologies.

States may develop their own Hg allocations methodologies, provided allocation information is submitted to EPA in the required time frame. (Unit-level allocations and the related comments are discussed in greater detail elsewhere in this action. This includes a discussion of the provisions establishing the advance notice States must provide for unit-by-unit allocations.)

3. What Sources Are Affected under the Model Cap-and-Trade Rule?

In the January 2004 NPR, EPA proposed a method for developing budgets that assumed reductions only from coal-fired Utility Units. Utility Units were defined as: coal-fired, non-cogeneration electric utility steam generating units serving a generator with a nameplate capacity of greater than 25 MWe; and coal-fired cogeneration electric utility steam generating units meeting certain criteria (referred to as the "one-third potential electric output capacity criteria"). In the SNPR, EPA proposed a model cap-and-trade rule that applied to the same categories of sources. We are finalizing the nameplate capacity cut-off that we proposed in the NPR for developing budgets and that we proposed in the SNPR for the applicability of the model trading rules. We are also finalizing the "fossil fuel-fired" definition and the one-third electric output capacity

criteria that were proposed. The actual rule language in the SNPR describing the sources to which the model rules apply is being slightly revised to be clearer in response to some comments that the proposed language was not clear.

i. 25 MW cut-off.

EPA is retaining the 25 MW cut-off for Utility Units for budget and model rule purposes. EPA believes it is reasonable to assume no further control of air emissions from smaller Utility Units. Available air emissions data indicate that the collective emissions from small Utility Units are relatively small and that further regulating their emissions would be burdensome, to both the regulated community and regulators, given the relatively large number of such units. For example, Hg emissions from Utility Units of 25 MWe or less in the U.S. represent approximately [??] percent of Hg emissions from Utility Units, respectively. Consequently, EPA believes that administrative actions to control this large group with small emissions would be inordinate and thus does not believe these small units should be included. This approach of using a 25 MWe cut-off for Utility Units is consistent with existing SO₂ and NO_x cap-and-trade programs such as the NO_x SIP Call (where existing and new Utility Units at or under this cut-off are, for similar reasons, not required to be included) and the Acid Rain Program (where this cut-off is applied to existing units and to new units combusting clean fuel).

ii. Definition of coal-fired.

EPA is finalizing the proposed definition of coal-fired, i.e., where any amount of coal or coal-derived fuel is used at any time. This is similar to the definition that is used in the Acid Rain Program to identify coal-fired units. EPA did not receive comments on this definition except that one commenter stated that coal refuse-fired plants should not be subject to CAMR. EPA points out that coal refuse is already subject to other Utility Unit programs, such as the Acid Rain program, the NSPS program (40 CFR part 60, subpart Da), and the CAIR program. Consequently, EPA rejects the commenter's request to not be included in the CAMR program.

iii. Exemption for cogeneration units.

As proposed, EPA is finalizing an exemption from the model cap-and-trade program for cogeneration units, i.e., units having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through sequential use of energy and meeting certain operating standards (discussed below). EPA is adopting, with some clarifications, the proposed definition of cogeneration unit and the proposed criteria for determining which cogeneration units qualify for the exemption from the model cap-and-trade programs.

a. One-third potential electric output capacity.

EPA is finalizing the one-third potential electric

output capacity criteria in the NPR and SNPR with some clarifications. Under the final rule, the following cogeneration units are Utility Units: any cogeneration unit serving a generator with a nameplate capacity of greater than 25 MWe and supplying more than one-third potential electric output capacity and more than 25 MWe annually to any utility power distribution system for sale. These criteria are similar to the definition in the proposals with the clarification that the criteria be applied on an annual basis. These criteria are the same used in the CAIR and are similar to those used in the Acid Rain Program to determine whether a cogeneration unit is a Utility Unit and the NO_x SIP Call to determine whether a cogeneration unit is an Utility Unit or a non-Utility Unit. The primary difference between the proposed criteria and the one-third potential electric criteria for the Acid Rain and NO_x SIP Call programs is that these programs applied the criteria to the initial operation of the unit and then to 3-year rolling average periods while the final CAMR criteria are applied to each individual year starting with the commencement of operation. EPA believes that using an individual year approach will streamline the application and administration of this exemption.

Some commenters supported that the one-third criteria be applied on annual basis and supported that the criteria be consistent with CAIR and the Acid Rain program. Several

commenters suggested exempting all cogeneration units instead of using the proposed criteria and cite the high efficiency of cogeneration as a reason for a complete exemption. EPA believes it is important to include in the CAMR program all units, including cogeneration units, that are substantially in the business of selling electricity. The proposed one-third potential electric output criteria described above are intended to do that.

Inclusion of all units substantially in the electricity sales business minimizes the potential for shifting utilization, and emissions, from regulated to unregulated units in that business and thereby freeing up allowances, with the result that total emissions from generation of electricity for sale exceed the CAMR emission cap. The fact that units in the electricity sales business are generally interconnected through their access to the grid significantly increases the potential for utilization shifting.

b. Clarifying "for sale."

Several commenters requested EPA confirm that, for purposes of applying the one-third potential electric output criteria, simultaneous purchases and sales of electricity are to be measured on a "net" basis, as is done in the Acid Rain Program. EPA confirms that, for purposes of applying the one-third potential electric output criteria in the CAMR program and the model cap-and-trade rules, the only

electricity that counts as a sale is electricity produced by a unit that actually flows to a utility power distribution system from the unit. Electricity that is produced by the unit and used on-site by the electricity-consuming component of the facility will not count, including cogenerated electricity that is simultaneously purchased by the utility and sold back to such facility under purchase and sale agreements under the Public Utilities Regulatory Policy Act of 1978 (PURPA). However, electric purchases and sales that are not simultaneous will not be netted; the one-third potential electric output criteria will be applied on a gross basis, except for simultaneous purchase and sales. This is consistent with the approach taken in the Acid Rain Program.

c. Multiple cogeneration units.

Some commenters suggested aggregating multiple cogeneration units that are connected to a utility distribution system through a single point when applying the one-third potential electric output capacity criteria. According to the commenters, facilities may have some cogeneration units over the size threshold for inclusion in the rule, while others may be below it. These commenters suggested that it is not feasible to determine which unit is producing the electricity exported to the outside grid. EPA proposed to determine whether a unit is affected by the CAMR on an individual-unit basis. This unit-based approach is

consistent with both the Acid Rain Program and the NO_x SIP Call. EPA considers this approach to be feasible based on experience from these existing programs, including for sources with multiple cogeneration units. EPA is unaware of any instances of cogeneration unit owners being unable to determine how to apply the one-third potential electric output capacity criteria where there are multiple cogeneration units at a source.

In a case where there are multiple cogeneration units with only one connection to a utility power distribution system, the electricity supplied to the utility distribution system can be apportioned among the units in order to apply the one-third potential electric output capacity criteria. A reasonable basis for such apportionment must be developed based on the particular circumstances. The most accurate way of apportioning the electricity supplied to the utility power distribution system seems to be apportionment based on the amount of electricity produced by each unit during the relevant period of time.

iv. Proposed low-emitter exclusion.

In the January 30, 2004 NPR, EPA took comment on the possibility of excluding from the Phase II cap units with low Hg emissions rates (e.g., emitting less than 25 pounds per year, lb/yr). In today's final rule, EPA is not finalizing a low-emitter exclusion. In proposing the possible low-emitter exclusion, EPA was concerned about the

rulemakings impact on small business entities. EPA also indicated concern about units with low Hg emissions rate because the new, Hg-specific control technologies that we expect to be developed prior to the Phase II cap deadline may not practicably apply to such units. The 1999 ICR data indicated that the 396 smallest emitting coal-fired units account for less than 5 percent of total Hg emissions. EPA also indicated in the proposal that there is reason to believe that the 15 ton Phase II cap can be achieved in a cost-effective manner, even if the lowest emitting 396 units are excluded from coverage under this cap.

Several commenters supported the provision excluding low-emitting units from the cap-and-trade program, while other commenters expressed opposition to the provision. Several commenters further suggested that, if the Agency excludes these units in a cap-and-trade program, the overall Hg emissions cap should not be reduced by the amounts that these sources emit (i.e., the 2018 cap should remain 15 tons even if these sources are excluded from the program). Some commenters supported other options for the exclusion, including an exclusion that started in Phase I, an exclusion based on 50 lb/yr, and an exclusion based on 100 to 140 MWe size cut-off.

As stated earlier, the low-emitter exclusion was proposed to address small business entities. Small business entities, however, are not necessarily small emission

emitters. Of the 396 units with estimated Hg emissions under 25 lb in 1999, most (about 95 percent) are not owned by small entities and a significant amount (about 10 percent) are large-capacity units (i.e., greater than 250 MWe). In addition, removing low-emitters from the trading program could increase costs, because a significant amount of the 396 units are large-capacity units that might be expected to be net sellers of allowances because they are already achieving emission reductions. Therefore, EPA maintains that the low-emitter exclusion may not be the best way to address small entity burden. For today's final CAMR, EPA is not finalizing a low-emitter exclusion and EPA recommends States address small entities through the allocation process. For example, States could provide a minimum Phase II allocation for small entities (e.g., allocation based on projected 2010 unit emissions). EPA also maintains that the cap-and-trade program and the 25 MWe size cut-off minimizes the burden for small business entities by ensuring that compliance is met in a least-cost fashion.

4. How Are Emission Allowances Allocated to Sources?

It is important to ensure that: the integrity of the cap-and-trade approach is preserved so that the required emissions reductions are achieved; the compliance and administrative costs are minimized; and source owners and operators are equitably treated. Accordingly, EPA believes

that some limited differences, such as allowance allocation methodologies are possible without jeopardizing the environmental and other goals of the cap-and-trade program.

i. Allocation of Hg allowances.

Each State participating in the EPA-administered cap-and-trade programs must develop a method for allocating (i.e., distributing) an amount of allowances authorizing the emissions tonnage of the State's CAMR budget. Each State has the flexibility to allocate its allowances however they choose, so long as certain timing requirements are met.

ii. Required aspects of a State Hg allocation approach.

Although it is EPA's intent to provide States with as much flexibility as possible in developing allocation approach, there are some aspects of State allocations that must be consistent for all States. All State allocation systems are required to include specific provisions that establish when States notify EPA and sources of the unit-by-unit allocations. These provisions establish a deadline for each State to submit to EPA its unit-by-unit allocations for processing into the electronic allowance tracking system. Because the Administrator will then expeditiously record the submitted allowance allocations, sources will thereby be notified of, and have access to, allocations with a minimum lead time (about three years) before the allowances can be used to meet the Hg emission limit.

Today's action finalizes the proposal to require States to submit unit-by-unit allocations of allowances for a given year no less than three years prior to January 1 of the allowance vintage year; this approach was supported by commenters. Requiring States to submit allocations and thereby provide a minimum lead time before the allowances can be used to meet the Hg emission limit ensures that an affected source, regardless of the State in which the unit is located, will have sufficient time to plan for compliance and implement their compliance planning. Allocating allowances less than three years in advance of the compliance year may reduce a CAMR unit's ability to plan for and implement compliance and, consequently, increase compliance costs. For example, shorter lead time will reduce the period for buying or selling allowances and could prevent sources from participating in allowance futures markets, a mechanism for hedging risk and lowering costs.

Further, requiring a uniform, minimum lead-time for submission of allocations allows EPA to perform its allocation-recordation activities in a coordinated and efficient manner in order to complete expeditiously the recordation and thereby promote a fair and competitive allowance market across the region.

iii. Flexibility and options for a State Hg allowance allocations approach.

Allowance allocation decisions in a cap-and-trade

program raise essentially distributional issues, as economic forces are expected to result in economically least-cost and environmentally similar outcomes regardless of the manner in which allowances are initially distributed. Consequently, States are given latitude in developing their Hg allocation approach. Hg allocation methodology elements for which States will have flexibility include:

- The cost of the allowance distribution (e.g., free distribution or auction);
- The frequency of allocations (e.g., permanent or periodically updated);
- The basis for distributing the allowances (e.g., heat-input or power output); and,
- The use of allowance set-asides and their size, if used (e.g., new unit set-asides or set asides for energy efficiency, for development of IGCC generation, for renewables, or for small units).

Some commenters have argued against giving States flexibility in determining allocations, citing concerns about complexity of operating in different markets and about the robustness of the trading system. EPA maintains that offering such flexibility, as it did in the NO_x SIP call, does not compromise the effectiveness of the trading program while maintaining the principle of federalism.

A number of commenters have argued against allowing (or requiring) the use of allowance auctions, while others did

not believe that EPA should recommend auctions. For today's final action, although there are some clear potential benefits to using auctions for allocating allowances (as noted in the SNPR), EPA believes that the decision regarding utilizing auctions rightly belongs to the States and Tribes. EPA is not requiring, restricting, or barring State use of auctions for allocating allowances.

A number of commenters supported allowing the use of allowance set-asides for various purposes. In today's final action, EPA is leaving the decision on using set-asides up to the States, so that States may craft their allocation approach to meet their State-specific policy goals.

iv. Example allowance Hg allocation methodology.

In the SNPR, EPA included an example (offered for informational guidance) of an allocation methodology that includes allowances for new generation and is administratively straightforward. EPA is including in today's preamble, this "modified output" example allocations approach, as was outlined in the SNPR.

EPA maintains that the choice of allocation methodology does not affect the achievement of the specific environmental goals of the CAMR program. This methodology is offered simply as an example, and individual States retain full latitude to make their own choices regarding what type of allocation method to adopt for Hg allowances and are not bound in any way to adopt the EPA's example.

This example method involves input-based allocations for existing coal units (with different ratios based on coal type), with updating to take into account new generation on a modified-output basis. It also utilizes a new source set-aside for new units that have not yet established baseline data to be used for updating. Providing allowances for new sources would address a number of commenter concerns about the negative effect of new units not having access to allowances.

As discussed in the methodology for determining State budgets, many comments were received on the use of coal adjustment factors for the allocation process. In the NPR and SNPR, EPA proposed that if states want to have allocations reflect the difficulty of controlling Hg, they might consider multiplying the baseline heat input data by ratios based on coal type, similar to the methodology used to establish the State Hg budgets in today's final rulemaking. In today's rulemaking for the purposes of establishing State budgets, EPA is using the coal adjustment factors of 1.0 for bituminous coals, 1.25 for subbituminous coals and 3.0 for lignite coals. In this example allocation methodology for States, EPA is also using these adjustment factors.

Under the example method, allocations are made from the State's Hg budget for the first five control periods (2010 through 2014) of the model cap-and-trade program for

existing sources on the basis of historic baseline heat input. EPA proposed January 1, 2000 cut-off on-line date for considering units as existing units. The cut-off on-line date was selected so that any unit meeting the cut-off date would have at least five years of operating data, i.e., data for 2000 through 2004. EPA is concerned with ensuring that particular units are not disadvantaged in their allocations by having insufficient operating data on which to base the allocations. EPA believes that a 5-year window, starting from commencement of operation, gives units adequate time to collect sufficient data to provide a fair assessment of their operations. Annual operating data is now available for 2003. EPA is finalizing January 1, 2000 as the cut-off on-line date for considering units as existing units because units meeting the cut-off date will have at least five years of operating data (i.e., data for 2001 through 2004).

The allowances for 2015 and later will be allocated from the State's Hg budget annually, six years in advance, taking into account output data from new units with established baselines (modified by the heat input conversion factor to yield heat input numbers). As new units enter into service and establish a baseline, they are allocated allowances in proportion to their share of the total calculated heat input (which is existing unit heat input plus new units' modified output). Allowances allocated to

existing units slowly decline as their share of total calculated heat input decreases with the entry of new units. After five years of operation, a new unit will have an adequate operating baseline of output data to be incorporated into the calculations for allocations to all affected units. The average of the highest three years from these five years will be multiplied by the heat-input conversion factor to calculate the heat input value that will be used to determine the new unit's allocation from the pool of allowances for all sources.

Under the EPA example method, existing units as a group will not update their heat input. This will eliminate the potential for a generation subsidy (and efficiency loss) as well as any potential incentive for less efficient existing units to generate more. This methodology will also be easier to implement because it will not require the updating of existing units' baseline data. Retired units will continue to receive allowances indefinitely, thereby creating an incentive to retire less efficient units instead of continuing to operate them in order to maintain the allowance allocations.

Moreover, new units as a group will only update their heat input numbers once - for the initial 5-year baseline period after they start operating. This will reduce any potential generation subsidy and be easier to implement, because it will not require the collection and processing of

data needed for regular updating.

The EPA believes that allocating to existing units based on a baseline of historic heat input data (rather than output data) is desirable, because accurate protocols currently exist for monitoring this data and reporting it to EPA, and several years of certified data are available for most of the affected sources. EPA expects that any problems with standardizing and collecting output data, to the extent that they exist, can be resolved in time for their use for new unit calculations. Given that units keep track of electricity output for commercial purposes, this is not likely to be a significant problem.

In its example, EPA is allocating to existing units by heat input and including adjustments by coal type (1.0 for bituminous coals, 1.25 for subbituminous coals, and 3.0 for lignite coals). However, EPA is not finalizing adjustments by coal type with the modified output approach, because we do not want to favor any particular new coal generation. Allocating to new (not existing) sources on the basis of input would serve to subsidize less-efficient new generation. For a given amount of generation, more efficient units will have the lower fuel input or heat input. Allocating to new units based on heat input could encourage the building of less efficient units because they would get more allowances than an equivalent efficient, lower heat-input unit. The modified output approach, as

described below, will encourage new, clean generation and will not reward less efficient new units.

Under the example method, allowances will be allocated to new units with an appropriate baseline on a "modified output" basis. The new unit's modified output will be calculated by multiplying its gross output by a heat rate conversion factor of 8,000 Btu per kilowatt-hour (Btu/kWh). The 8,000 Btu/kWh value for the conversion factor is an average of heat-rates for new pulverized coal plants and new IGCC coal plants (based upon assumptions in EPA's economic modeling analysis). See documentation for the IPM at <http://www.epa.gov/airmarkets/epa-ipm/attachment-h.pdf>). A single conversion rate will create consistent and level incentives for efficient generation, rather than favoring new units with higher heat rates.

For new cogeneration units, their share of the allowances will be calculated by converting the available thermal output (Btu) of useable steam from a boiler or useable heat from a heat exchanger to an equivalent heat input by dividing the total thermal output (Btu) by a general boiler/heat exchanger efficiency of 80 percent.

Steam and heat output, like electrical output, is a useable form of energy that can be utilized to power other processes. Because it would be nearly impossible to adequately define the efficiency in converting steam energy into the final product for all of the various processes,

this approach focuses on the efficiency of a cogeneration unit in capturing energy in the form of steam or heat from the fuel input.

Commenters expressed concern about a single conversion factor, arguing for different factors for different coals and technologies. EPA maintains that providing each new source an equal amount of allowances per MWh of output is an equitable approach. Because electricity output is the ultimate product being produced by electric generating unit, a single conversion factor based on output ensures that all sources will be treated equally. Higher conversion factors for less efficient technologies will effectively provide greater amounts of allowances (and thus a greater subsidy) to such less efficient units for each MWh they generate. This will serve to provide greater relative incentives to build new less efficient technologies rather than efficient technology. It should also be noted that, because all allocations are proportionally reduced after a new source is integrated into the market, higher conversion factors also lower allocations to existing sources.

Today's example method includes a new source set-aside equal to 5 percent of the State's emission budget for the years 2010 to 2014 and 3 percent of the State's emission budget for the subsequent years. In the SNPR, EPA proposed a level 2 percent set aside for all years.

Commenters supported a new source set-aside and one

commenter pointed to EIA forecasts for coal to grow by 112 gigawatts (GW) by 2025. EPA economic modeling projects growth in coal by 2020. In order to estimate the need for allocations for new units, EPA considered projected growth in coal generation and the resulting Hg emissions portion of the Hg national cap. EPA believes the example new source set-aside would provide for that growth.

Individual States using a version of the example method may want to adjust this initial five year set-aside amount to a number higher or lower than 5 percent to the extent that they expect to have more or less new generation going on-line during the 2001 to 2013 period. They may also want to adjust the subsequent set-aside amount to a number higher or lower than 2 percent to the extent that they expect more or less new generation going on-line after 2004. States may also want to set this percentage a little higher than the expected need, because, in the event that the amount of the set-aside exceeds the need for new unit allowances, the State may want to provide that any unused set-aside allowances will be redistributed to existing units in proportion to their existing allocations.

For the example method, EPA is assuming that new units will begin receiving allowances from the State- or Tribal-established set-aside for the control period immediately following the control period in which the new unit commences commercial operation, based on the unit's emissions for the

preceding control period. For instance, a source might be required to hold allowances during its start-up year, but will not receive an allocation for that year.

States will allocate allowances from the set-aside to all new units in any given year as a group. If there are more allowances requested than in the set-aside, allowances will be distributed on a pro-rata basis. Allowance allocations for a given new unit in following years will continue to be based on the prior year's emissions until the new unit establishes a baseline, is treated as an existing unit, and is allocated allowances through the State's updating process. This will enable new units to have a good sense of the amount of allowances they will likely receive - in proportion to their emissions for the previous year. This methodology will not provide allowances to a unit in its first year of operation; however it is a methodology that is straightforward, reasonable to implement, and predictable.

Although EPA is offering an example allocation method with accompanying regulatory language, EPA reiterates that it recognizes States' flexibility in choosing their NO_x allocations method. Several commenters, for instance, have noted their desire for full output-based allocations (in contrast to the hybrid approach in the example above). In the past, the EPA had sponsored a work-group to assist States wishing to adopt output-based NO_x allocations for the

NO_x SIP Call. Documents from meetings of this group and the resulting guidance report (found at <http://www.epa.gov/airmarkets/fednox/workgrp.html>) together with additional resources such as the EPA-sponsored report "Output-Based Regulations: A Handbook for Air Regulators" (found at http://www.epa.gov/cleanenergy/pdf/output_rpt.pdf) can help States, should they choose to adopt any output-based elements in their allocation plans.

As an another alternative example, States could decide to include elements of auctions into their allowance allocation programs.⁵ An example of an approach where CAMR allowances could be distributed to sources through a combination of an auction and a free allocation is provided below.

During the first year of the trading program, 94 percent of the Hg allowances could, for example, be allocated to affected units with an auction held for the remaining 1 percent of the Hg allowances.⁶ Each subsequent year, an additional 1 percent of the allowances (for the first 20 years of the program), and then an additional 2.5 percent thereafter, could be auctioned until eventually all the allowances are auctioned. With such a system, for the first 20 years of the trading programs, the majority of

⁵ Auctions could provide States with a less distortionary source of revenue.

⁶ 5 percent of the allowances will go to a new source set aside.

allowances could be distributed for free via the allocation. Allowances allocated for these earlier years are generally more valuable than allowances allocated for later years because of the time value of money. Thus, most emitting units could receive relatively more allowances in the early years of the program, when they would be facing the higher expenses of taking action to control their emissions.

Auctions could be designed by the State to promote an efficient distribution of allowances and a competitive market. Allowances could be offered for sale before or during the year for which such allowances may be used to meet the requirement to hold allowances. States will decide on the frequency and timing of auctions. Each auction could be open to any person, who could submit bids according to auction procedures, a bidding schedule, a bidding means, and by fulfilling requirements for financial guarantees as specified by the State. Winning bids, and required payments, for allowances could be determined in accordance with the State program and ownership of allowances will be recorded in the EPA Allowance Tracking System after the required payment is received.

The auction could be a multiple-round auction. Interested bidders could submit before the auction, one or more initial bids to purchase a specified quantity of Hg allowances at a reserve price specified by the State, specifying the appropriate account in the Allowance Tracking

System in which such allowances will be recorded. Each bid could be guaranteed by a certified check, a funds transfer, or, in a form acceptable to the State, a letter of credit for such quantity multiplied by the reserve price. For each round of the auction, the State would announce current round reserve prices for Hg and determine whether the sum of the acceptable bids exceeds the quantity of such allowances available for auction. If the sum of the acceptable bids for Hg allowances exceeds the quantity of such allowances the State would increase the reserve price for the next round. After the auction, the State will publish the names of winning and losing bidders, their quantities awarded, and the final prices. The State will return payment to unsuccessful bidders and add any unsold allowances to the next relevant auction.

In summary, today's action provides, for States participating in the EPA-administered CAMR cap-and-trade program, the flexibility to determine their own methods for allocating Hg allowances to their sources. Specifically, such States will have flexibility concerning the cost of the allowance distribution, the frequency of allocations, the basis for distributing the allowances, and the use and size of allowance set-asides.

5. What Mechanisms Affect the Trading of Emission Allowances?

i. Banking.

a. The CAMR NPR and SNPR proposal for the model rule and input from commenters.

Banking is the retention of unused allowances from one calendar year for use in a later calendar year. Banking allows sources to make reductions beyond required levels and "bank" the unused allowances for use later. Generally, banking has several advantages: (a) Banking results in early reductions as companies over-control their emissions; it is very unlikely that significant levels of early reductions would occur without banking. (b) Banked allowances can be used at any time so, they provide flexibility for companies to respond to growth and changing marketplace conditions over time. (c) Banking can result in emissions above the cap level in the later years of the compliance period, however, because the cap is permanent banking does not result in an increase in *cumulative* emissions. This is an important trade-off for getting early reductions.

The January 30, 2004 NPR and March 16, 2004 SNPR proposed that the Hg cap-and-trade program allow banking after the start of the Hg trading program, and that use of banked allowances be allowed without restrictions.

Comments Regarding Unrestricted Banking After the Start of the Hg Cap-and-Trade Program

Many commenters supported EPA's proposal to allow unrestricted banking and the use of banked Hg allowances.

Further, they agreed that banking with no restrictions on use will encourage early emissions reductions, stimulate the trading market, encourage efficient pollution control, and provide flexibility to affected sources in meeting environmental objectives. A few commenters opposed EPA's proposal of banking without restriction after the start of the Hg cap-and-trade program. These commenters generally pointed out that allowing unrestricted banking delays the achievement of the second phase cap.

b. The final Hg model rule and banking.

Banking of allowances provides flexibility to sources, encourages earlier or greater reductions than required, stimulates the market, and encourages efficiency. EPA has acknowledged that allowing unrestricted banking after the start of the program will result in the second phase cap being achieved over a longer timeframe but it will also yield greater cumulative reductions early in the program than would be required by the program cap. Furthermore, banking does not reduce the overall reduction requirement, and will not affect cumulative Hg reductions over the full course of the program. EPA is finalizing that banking will be allowed without restriction after the start of the Hg cap-and-trade program (from the start of the program to when the 15-ton cap is achieved).

ii. Hg safety valve mechanism.

a. The CAMR NPR and SNPR proposal for the safety valve and

input from commenters.

In the January 30, 2004 NPR and March 16, 2004 SNPR, EPA proposed a safety valve provision that set the maximum cost purchasers must pay for Hg emissions allowances. This provision was intended to address some of the uncertainty associated with the cost of Hg control.

Under the safety valve mechanism, the price of allowances is effectively (although not legally) capped. Sources may purchase allowances from subsequent year budgets at the safety-valve price at any time. However, it is unlikely they would do so unless the market allowance price exceeded the safety valve price. The purpose of this provision is to minimize unanticipated market volatility and provide more market information that industry can rely upon for compliance decisions. The safety valve mechanism ensures the cost of control does not exceed a certain level, but also ensures that emissions reductions are achieved. The future year cap is reduced by the borrowed amount, ensuring the integrity of the caps.

EPA proposed a price of \$2,187.50 for a Hg allowance (covering one oz) and that this price would be annually adjusted for inflation. EPA also proposed that the permitting authority deduct corresponding allowances from future allowance budgets. EPA noted that the safety valve mechanism would need to be incorporated into a State's chosen allocations methodology to ensure the availability of

un-distributed allowances from which purchasers could borrow. Making allowances available through the safety valve without taking them away from future budgets would undermine the integrity of the cap.

Comments regarding the need for safety valve

Many commenters supported the inclusion of a safety valve to reduce market uncertainty and guarantee a maximum price at which emissions allowances can be purchased. These commenters generally cited uncertainty pertaining to technology availability and cost as the reason for their support. Other commenters suggested that the safety valve provision should be eliminated. Some of these commenters noted that EPA's cost analysis of the cap-and-trade program was projecting that a safety valve price of \$2,187.50/oz would be triggered, delaying achievement of the cap. Other commenters noted that the safety valve provision could contribute to Hg "hot spots," and that the provision is counter to market-based approach.

b. The final Hg model rule and the safety valve.

EPA will not include a Hg safety valve mechanism in today's final rule. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with Hg reduction requirements under CAMR.

EPA maintains that the design of the CAMR trading program, a two-phased approach of 38 tpy in 2010 and 15 tpy in 2018, reduces the likelihood of extreme market volatility

that the safety valve was intended to mitigate. The program includes a cap in the first phase based on the Hg co-benefit reductions expected under the CAIR program for SO₂ and NO_x. In addition, the program provides lead time for compliance for each phase and allows banking of allowances in the first phase, which provides flexibility in achieving emissions reductions under the second phase. EPA experience with the Acid Rain program and the NO_x Budget Program indicates that market volatility has not been a significant factor in these trading programs, and that it has been greater during the early years of the programs. EPA believes that setting the first phase Hg cap at CAIR co-benefits should limit market volatility caused by uncertainty early in the program.

EPA also maintains that the timelines and caps of the CAMR trading program achieve emission reductions without unacceptable costs. The first phase cap of the program is based on co-benefit reduction expected under the CAIR program, and second phase cap represents a level of reductions that EPA has determined can be achieved without very high marginal costs, especially given recent advancements in the area of Hg control technology. EPA's economic modeling of the CAMR program (see Chapter 8 of RIA) projects that in the first phase of the program, the marginal cost of control remains under \$35,000 per lb (the proposed safety valve price). Although in the second phase of the CAMR program, economic modeling projects marginal

costs above this level, the modeling assumes no improvements in the cost of Hg control technology over time. Given that this is the first time Hg from coal-fired utilities is being addressed by Federal regulation, and given the current level of research and demonstration of Hg control technologies, control cost are expected to improve over time. Because of the uncertainty around Hg control technologies like ACI, EPA has conservatively included no cost improvement in its basic modeling assumptions. Given the development in advanced sorbents for ACI, EPA examined the impact of Hg technology improvements by providing a lower cost Hg control option in future years. That modeling projected Hg marginal costs below \$35,000/lb.

6. What Are the Source-Level Emissions Monitoring and Reporting Requirements?

Today's rule adds subpart I to 40 CFR part 75. Subpart I specifies the basic emission monitoring requirements necessary to administer a Hg trading program for new and existing Utility Units. Today's rule also revises the regulatory language at several places in 40 CFR parts 72 and 75, to include specific Hg monitoring definitions and provisions, in support of 40 CFR part 75, subpart I. Affected units will be required to comply with these Hg monitoring provisions, if and when 40 CFR part 75, subpart I is adopted by State or Tribal agencies as part of a Hg cap-and-trade program. The changes to 40 CFR part 75 are

discussed in greater detail elsewhere in this action.

Monitoring and reporting of an affected source's emissions are integral parts of any cap-and-trade program. Consistent and accurate measurement of emissions ensures that each allowance actually represents one oz of emissions and that one oz of reported emissions from one source is equivalent to one oz of reported emissions from another source. This establishes the integrity of each allowance and instills confidence in the market mechanisms that are designed to provide sources with flexibility in achieving compliance. Those flexibilities result in substantial cost savings to the industry.

Given the variability in the unit type, manner of operation, and fuel mix among coal-fired Utility Units, EPA believes that emissions must be monitored continuously in order to ensure the precision, reliability, accuracy, and timeliness of emissions data that support the cap-and-trade program. Today's rule allows two methodologies for continuously monitoring Hg emissions: (1) Hg continuous CEMS; and (2) sorbent trap monitoring systems. Based on preliminary evaluations, EPA believes it is reasonable to expect that both technologies will be well-developed by the time a Hg emissions trading program is implemented.

In the SNPR, EPA solicited comment on two alternative approaches for the continuous monitoring of Hg emissions. In the first alternative, most sources would be required to

use CEMS, with low-emitting sources having Hg mass emissions at or below a specified threshold value being allowed to use sorbent trap monitoring systems. In the second proposed alternative, all sources would be allowed to use either CEMS or sorbent trap monitoring systems. However, the sorbent trap systems would be subject to QA procedures comparable to those required for a CEMS, and the QA procedures would be more stringent for units with Hg mass emissions above a specified threshold value. Today's rule adopts a modification of the second proposed alternative. Sorbent trap monitoring systems may be used "across the board," provided that rigorous QA procedures are implemented. These QA requirements, which are found in 40 CFR 75.15 and in 40 CFR part 75, appendices B and K, are based on input from commenters and from EPA's own research. The proposed rule would have required quarterly relative accuracy audits for many of the sorbent trap systems. Today's rule replaces this proposed requirement with alternative procedures that are more suitable for sorbent trap systems.

For affected sources with Hg emissions at or below a specified threshold value, 40 CFR 75.81(b) of today's rule provides additional regulatory flexibility by allowing default Hg concentrations obtained from periodic Hg emission testing to be used to quantify Hg mass emissions, instead of continuously monitoring the Hg concentration. The use of this low mass emitter option is restricted to sources that

emit no more than 29 lb (464 oz) of Hg per year. The rationale for this threshold is given elsewhere in this action.

The amendments to 40 CFR part 75 set forth the specific monitoring and reporting requirements for Hg mass emissions and include the additional provisions necessary for a cap-and-trade program. 40 CFR part 75 is used in both the Acid Rain and the NO_x Budget Trading programs, and most sources affected by this rulemaking are already meeting the requirements of 40 CFR part 75 for one or both of those programs.

The final rule requires the measurement of total vapor phase Hg, but does not require separate monitoring of speciated Hg emissions (i.e., elemental and ionized Hg). As stated elsewhere in this action, EPA does not believe that utility-attributable hot spots will be an issue after implementation of CAIR and CAMR. Nevertheless, we are committed to monitoring closely the effects of utility emissions. We commit to, and retain authority to, address the situation appropriately. As part of this commitment, the Agency believes that it is important to understand and monitor the speciation profile of Hg emissions. However, the Agency does not believe that speciating Hg monitors are appropriate at this time. For this reason, the Agency considers separate monitoring of these emissions as a need to be addressed. However, at least two current monitoring

technologies can accurately monitor speciated Hg emissions. The Agency will continue to test speciated Hg monitoring technologies. If these technologies are adequately demonstrated, the Agency may consider a proposed rulemaking within four to five years after program implementation, which should provide enough lead time for development and installation of these monitoring systems.

In order to ensure program integrity, the model trading rule requires states to include year-round 40 CFR part 75 monitoring and reporting for Hg for all sources. Deadlines for monitor certification and other details are specified in the model rule. EPA believes that if these provisions are implemented, emissions will be accurately and consistently monitored and reported from unit-to-unit and from State-to-State.

As is required for the Acid Rain program and the NO_x Budget Trading program, Hg emissions data will be provided to EPA on a quarterly basis in a format specified by the Agency and submitted to EPA electronically using EPA provided software. We have found this centralized reporting requirement necessary to ensure consistent review, checking, and posting of the emissions and monitoring data from all affected sources, which contributes to the integrity and efficiency of the trading program.

Finally, consistent with the current requirements in Part 75 for the Acid Rain and the NO_x SIP Call programs, the

final rule allows sources, under 40 CFR 60.4175 of 40 CFR part 60, subpart HHHH, and under 40 CFR 75.80(h) of 40 CFR part 75, subpart I, to petition for an alternative to any of the specified monitoring requirements in the rule. This provision also provides sources with the flexibility to petition to use an alternative monitoring system under 40 CFR part 75, subpart E as long as the requirements of 40 CFR 75.66 are met.

7. Are There Additional Changes to Proposed Model Cap-and-Trade Rule Reflected in the Regulatory Language?

Today's final rule includes some minor changes to the model rule's regulatory text that improve the implementability of the rules or clarify aspects of the rules identified by EPA or commenters. (Note that elsewhere in this action are highlighted the more significant modifications included in the final model rules.)

These include:

- The definition of "nameplate capacity" is clarified;
- The language on closing of general accounts is clarified;
- Process of recordation of allowance allocations and transfers on rolling 30-year periods is added to make it consistent with Acid Rain regulations.

Another example of where today's final model trading rules incorporate relatively minor changes from the proposed

model trading rules involves the provisions in the standard requirements concerning liability under the trading programs. The proposed Hg model trading rule includes, under the standard requirements in the 40 CFR 60.4154(d)(3) provision stating that any person who knowingly violates the Hg trading programs or knowingly makes a false material statement under the trading programs will be subject to enforcement action under applicable State or Federal law. The final Hg model trading rule excludes this provision for the following reasons. First, the proposed rule provision is unnecessary because, even in its absence, applicable State or Federal law authorizes enforcement actions and penalties in the case of knowing violations or knowing submission of false statements. Moreover, this proposed rule provision is incomplete. It does not purport to cover, and has no impact on, liability for violations that are not knowingly committed or false submissions that are not knowingly made. Applicable State and Federal law already authorizes enforcement actions and penalties, under appropriate circumstances, for non-knowing violations or false submissions. Because the proposed rule provision is unnecessary and incomplete, the final model Hg trading rule does not include this provision. However, EPA emphasizes that, on its face, the provision that was proposed, but eliminated in the final rule, in no way limits liability, or the ability of the State or EPA to take enforcement action,

to only knowing violations or knowing false submissions.

E. Standard of Performance Requirements.

1. Introduction.

As proposed in the NPR and SNPR, under section 111, each State is required to submit a State Plan demonstrating that each State will meet the assigned Statewide Hg emission budget. Each State Plan should include fully-adopted State rules for the Hg reduction strategy with compliance dates providing for controls by 2010 and 2018.

The purpose of this section is to identify criteria for determining approvability of a State submittal in response to the performance standard requirements. This section also describes the actions the Agency intends to take if a State fails to submit a satisfactory plan. In addition, this section sets forth the criteria for States to receive approvability of trading rule within a State Plan.

2. Performance Standard Approvability Criteria

As discussed in the NPR and SNPR, CAA sections 111(a) and (d)(1) authorize EPA to promulgate a "standard of performance" that States must apply to existing sources through a State plan. As also discussed in the NPR and elsewhere in today's final rule, EPA is interpreting the term "standard of performance", as applied to existing sources, to include a cap-and-trade program.

The State budgets are not an independently enforceable requirement. Rather, each State must impose control

requirements that the State demonstrates will limit Statewide emissions from affected new and existing sources to the amount of the budget. Consistent with CAIR, EPA is finalizing that States may meet their Statewide emission budget by allowing their sources to participate in a national cap-and-trade program. That is, a State may authorize its affected sources to buy and sell allowances out of State, so that any difference between the State's budget and the total amount of Statewide emissions will be offset in another State (or States). Regardless of State participation in the national cap-and-trade program, EPA believes that the best way to assure this emission limitation is for the State to assign to each affected source, new and existing, an amount of allowances that sum to the State budget. Therefore, EPA is finalizing that all regulatory requirements be in the form of a maximum level of emissions (i.e., a cap) for the sources.

As proposed in the SNPR, EPA is finalizing that each State must submit a demonstration that it will meet its assigned Statewide emission budget, but that regardless of whether the State participates in a trading program, the State may allocate its allowances by its own methodology rather than following the method used by EPA to derive the state emissions budgets. This alternative approach is consistent with the approach in the CAIR.

Moreover, States remain authorized to require emissions

reductions beyond those required by the State budget, and nothing in today's final rule will preclude the States from requiring such stricter controls and still being eligible to participate in the Hg Budget Trading Program.

In addition, as proposed in the SNPR, EPA finalizes today that sources will be required to comply with the 40 CFR part 75 requirements finalized today. EPA believes that compliance with these requirements are necessary to demonstrate compliance with a mass emissions limit.

If a State fails to submit a State plan as proposed to be required in today's final rule, EPA will prescribe a Federal plan for that State, under CAA section 111(d)(2)(A). EPA proposes today's model rule as that Federal plan.

3. Approvability of Trading Rule Within a State Plan.

i. Necessary common components of trading rule.

As discussed in the SNPR and for today's final rule, EPA intends to approve the portion of any State's plan submission that adopts the model rule, provided: (1) the State has the legal authority to adopt the model rule and implement its responsibilities under the model rule, and (2) the State Plan submission accurately reflects the Hg reductions to be expected from the State's adoption of the model rule. Provided a State meets these two criteria, then EPA intends to approve the model rule portion of the State's plan submission.

State adoption of the model rule will ensure

consistency in certain key operational elements of the program among participating States, while allowing each State flexibility in other important program elements. Uniformity of the key operational elements is necessary to ensure a viable and efficient trading program with low transaction costs and minimum administrative costs for sources, States, and EPA. Consistency in areas such as allowance management, compliance, penalties, banking, emissions monitoring and reporting and accountability are essential.

The EPA's intent in issuing a model rule for the Hg Budget Trading Program is to provide States with a model program that serves as an approvable strategy for achieving the required reductions. States choosing to participate in the program will be responsible for adopting State regulations to support the Hg Budget Trading Program, and submitting those rules as part of the State Plan. There are two alternatives for a State to use in joining the Hg Budget Trading Program: incorporate 40 CFR part 60, subpart HHHH by reference into the State's regulations or adopt State regulations that mirror 40 CFR part 60, subpart HHHH, but for the potential variations described below.

Some variations and omissions from the model rule are acceptable in a State rule. This approach provides States flexibility while still ensuring the environmental results and administrative feasibility of the program. EPA

finalizes that in order for a State Plan to be approved for State participation in the Hg Budget Trading Program, the State rule should not deviate from the model rule except in the area of allowance allocation methodology. Allowances allocation methodology includes any updating system and any methodology for allocating to new units. Additionally, States may incorporate a mechanism for implementing more stringent controls at the State level within their allowance allocation methodology.

State plans incorporating a trading program that is not approved for inclusion in the Hg Budget Trading Program may still be acceptable for purposes of achieving some or all of a State's obligations provided the general criteria. However, only States participating in the Hg Budget Trading Program would be included in EPA's tracking systems for Hg emissions and allowances used to administer the multi-state trading program.

In terms of allocations, States must include an allocation section in their rule, conform to the timing requirements for submission of allocations to EPA that are described in this preamble, and allocate an amount of allowances that does not exceed their State trading program budget. However, States may allocate allowances to budget sources according to whatever methodology they choose. EPA has included an optional allocation methodology but States are free to allocate as they see fit within the bounds

specified above, and still receive State Plan approval for purposes of the Hg Budget Trading Program.

ii. Revisions to regulations.

As proposed in the SNPR, today's action finalizes revisions to the regulatory provisions in 40 CFR 60.21 and 60.24 to make clear that a standard of performance for existing sources under CAA section 111(d) may include an allowance program of the type described today.

F. What are the performance testing and other compliance provisions?

1. Summary of Major Comments and Responses.

a. Use of Sorbent Trap Monitoring Systems.

EPA proposed two alternatives for the use of sorbent trap monitoring systems. Alternative #1 would allow the use of sorbent trap systems for a subset of the affected units. The use of sorbent traps would be limited to low-emitting units, having estimated 3-year average Hg emissions of 144 oz (9 lb) or less, for the same three calendar years used to allocate the Hg allowances. The threshold value of 9 lb/yr year was based on 1999 data gathered by EPA under an ICR that appeared in the Federal Register on April 9, 1998. Based solely on the 1999 ICR data, 228 of the 1,120 coal-fired Utility Units in the database (i.e., 20 percent of the units), representing 1 percent of the 48 tons of estimated nationwide emissions, would qualify to use sorbent trap monitoring systems. EPA also took comment on three other

threshold values, i.e., 29 lb/yr, 46 lb/yr, and 76 lb/yr, representing, respectively, 435, 565, and 724 of the 1,120 units in the database.

Alternative #2 would allow any source to use either CEMS or sorbent traps. For sources with annual Hg emissions below a specified threshold value (we took comment on four values, i.e., 9 lb/yr, 29 lb/yr, 46 lb/yr, or 76 lb/yr), the QA requirements for sorbent trap monitoring systems would consist of the procedures in proposed Method 324 plus an annual relative accuracy test audit (RATA). For sources with annual Hg emissions above the specified threshold, quarterly relative accuracy (RA) testing (i.e., a full 9-run RATA once a year and 3-run RAAs in the other three quarters of the year) would be required in addition to the proposed Method 324 procedures.

EPA also requested comment on the appropriateness of proposed QA procedures for sorbent trap monitoring systems. Numerous commenters expressed concern that EPA's proposal was unfairly and unjustifiably biased against the sorbent trap method. The commenters did not support Alternative #1, because it restricts the use of sorbent traps to low emitting units. Commenters were generally more receptive to Alternative #2, except for the proposed quality control/quality assurance (QA/QC) procedures for sorbent trap systems (most notably the quarterly RA testing), which they found to be inappropriate, overly burdensome, costly,

and time-consuming. Several commenters stated that EPA has no justification for restricting the use of the sorbent trap method because it has been shown during EPA-sponsored Hg monitoring demonstrations that the method can achieve accuracies comparable, and in some cases better than those achieved by Hg CEMS. Other commenters recommended that the type of QA/QC procedures prescribed for sorbent trap systems should be more specific to the sorbent trap technology and should be more clearly defined. Finally, a number of commenters objected to the proposal to report the higher of the two Hg concentrations from the paired sorbent traps, and recommended that the results be averaged instead.

40 CFR 75.81(a) of today's final rule adopts a modified version of Alternative #2, which allows the use of sorbent trap systems for any affected unit, provided that rigorous, application-specific QA procedures are implemented. The operational and QA/QC procedures for sorbent trap systems are found in 40 CFR 75.15 and in 40 CFR part 75, appendices B and K of the final rule. EPA also has incorporated the recommendation of the commenters to use the average of the Hg concentrations measured by the paired sorbent traps. And in cases where one of the traps is accidentally lost, damaged, or broken, the owner or operator would be permitted to report the results of the analysis of the other trap, if valid.

Recent field test data from several different test

sites indicate that sorbent trap systems can be as accurate as Hg CEMS. Recent field tests have answered questions regarding which substances in the flue gas can interfere with accurate vapor phase Hg monitoring by sorbent traps. Sorbent trap technology also has evolved, with the addition of a third segment that enables the individual traps to be subject to enhanced QA procedures. And the Agency has been working with industry and equipment manufacturer representatives to develop new QA procedures that are more relevant to the operation of a sorbent trap system. These improved QA procedures are included in this rulemaking. In view of this, EPA believes that it is appropriate to extend the use of sorbent trap systems to all affected units.

EPA notes that although the restrictions on the use of sorbent traps have been removed, there are some inherent risks associated with the use of this monitoring approach. For instance, because sorbent traps may contain several days of accumulated Hg mass, the potential exists for long missing data periods, if the traps should be broken, compromised, or lost during transit or analysis, or if they fail to meet the QC criteria. Also, when a RATA of a sorbent trap system is performed, the results of the test cannot be known until the contents of the traps have been analyzed. If the results of the analysis are unsatisfactory, the RATA may have to be repeated. This also may result in a long missing data period. However, EPA

believes that these undesirable outcomes can be minimized by following the proper handling, chain of custody, and laboratory certification procedures in the final rule. The use of redundant backup monitoring systems can also help to reduce the amount of missing data substitution.

2. Compliance Flexibility for Low Emitters

The SNPR did not contain any special monitoring provisions for units with low mass emissions (LME). All affected units would be required to continuously monitor the Hg concentration, using either CEMS or sorbent trap monitoring systems.

Numerous commenters requested that EPA provide a less rigorous, cost-effective monitoring option for low emitting units. Affected units could meet a low emitter criterion based on a combination of unit size, operating time, and/or control device operation. Any marginal decrease in accuracy from less rigorous monitoring would have a minimal impact overall, because these units represent only a small percentage of the nationwide Hg mass emissions.

Consistent with the LME provisions in 40 CFR 75.19 for SO₂ and NO_x, 40 CFR 75.81(b) through (g) of the final rule provide a less rigorous monitoring option for low Hg emitters. These provisions allow sources with estimated annual emissions of 29 lb/yr (464 oz/yr) or less, representing about 5 percent of the nationwide Hg mass emissions, to use periodic emission testing to quantify

their Hg emissions, rather than continuously monitoring the Hg concentration. For units with Hg emissions of 9 lb/yr (144 oz/yr) or less, annual emission testing is required. For units with Hg emissions greater than 144 oz/yr but less than or equal to 464 oz/yr, semiannual testing is required. For reporting purposes, the owner or operator is required to use either the highest Hg concentration from the most recent emission testing or 0.50 micrograms per standard cubic meter ($\mu\text{g}/\text{scm}$), whichever is greater. If, at the end of a particular calendar year, the reported annual Hg mass emissions for a unit exceed 464 oz, the unit is disqualified as a low mass emitter and the owner or operator must install and certify a Hg CEMS or sorbent trap monitoring system within 180 days of the end of that year. The final rule also contains special low mass emitter provisions for common stack and multiple stack exhaust configurations.

The Agency believes that a low mass emitter provision can be beneficial to both EPA and industry. It is cost-effective for industry, in that it allows periodic stack testing to be used to estimate Hg emissions instead of requiring CEMS. In the context of a cap-and-trade program, a low emitter provision can provide environmental benefit, because it requires conservatively high default emission factors to be used for reporting, as explained in the paragraphs below. Also, allowing a subset of the affected units to use less rigorous monitoring reduces the

administrative burden of program implementation, allowing EPA to focus its attention on the higher-emitting sources.

Selecting an appropriate low emitter cutoff point is of critical importance. On the one hand, if the cutoff point is too low (i.e., too exclusive) this would not be cost-effective for the regulated sources and would greatly increase the burden on the regulatory agencies to implement and maintain the program. On the other hand, if the cutoff point is too high (i.e., too inclusive), this would create inequities in the trading market.

Over the years, EPA has used a de minimus concept to either exempt low-emitting sources from monitoring or to allow these sources to use less rigorous, lower cost techniques to monitor emissions instead of installing CEMS:

- In the preamble of the 1993 Acid Rain Program (ARP) final rule (see 58 FR 3593, January 11, 1993), EPA's Acid Rain Division (now the Clean Air Markets Division, CAMD) first used the de minimus concept to exempt certain new Utility Units from the Acid Rain Program (i.e., units \leq 25 MW that burn only fuels with a sulfur content \leq 0.05 percent by weight);
- EPA also allows gas-fired and oil-fired peaking units to use the less costly methodology in 40 CFR part 75, appendix E to estimate NO_x emissions instead of using CEMS, because the Agency's

analyses indicated that projected NO_x emissions from these units represent less than 1 percent of the total NO_x emissions from Acid Rain Program units.

- In 1998, EPA promulgated LME provisions in section 75.19 for SO₂ and NO_x (see 63 FR 57484, October 27, 1998). These provisions require the use of conservatively high default emission rates to quantify SO₂ and NO_x emissions. EPA determined the appropriate SO₂ and NO_x mass emissions thresholds or "cutoff points" for unit to qualify as a low mass emissions methodology, considering inventory and regulatory changes that had taken place since the original 1993 Acid Rain rulemaking. The selected threshold values were based on a de minimus concept, i.e., the SO₂ and NO_x emissions from the units that could potentially qualify to use the LME methodology represented less than or equal to 1 percent of the emissions from all affected units.

In 1999, EPA obtained Hg mass emissions estimates for the 1,120 utility units affected by the SNPR, as the result of an ICR that appeared in the Federal Register on April 9, 1998. These data show that if a low Hg mass emission threshold of 9 lb/yr were selected, 228 units, representing 1 percent of the total annual Hg emissions from coal-fired

electric utility units in the U.S., could potentially qualify to use the low emitter option. However, EPA's analysis also indicated that by raising the cutoff point to 29 lb/yr, almost twice the number of units (435), representing just 5 percent of the total annual Hg emissions, could potentially qualify as low emitters. Therefore, EPA has decided to adopt the 29 lb/yr as the qualifying low mass emission threshold for Hg.

Although the 5 percent threshold represents a departure from the traditional de minimus value of 1 percent, the Agency believes that allowing units with Hg emissions of 29 lbs/yr or less to use the low mass emitter option is a better choice, for both economic and environmental reasons. For continuous monitoring methodologies, the annualized cost per unit will be about \$89,500 for testing, maintenance, and operation. For sorbent trap methodologies, the annualized cost per unit will be about \$113,000 for testing, maintenance, and operation. For a unit that emits between 9 lb/yr and 29 lb/yr of Hg, if the owner or operator elects to use the low emitter option, today's rule would require two stack tests per year (at \$5,500 each), and an estimated \$1,500 annual cost for technical calculation, labor, and other associated costs, for a total annual expenditure per unit of around \$12,500. Therefore, for the approximately 207 units with Hg mass emissions between 9 and 29 lb/yr, the potential savings associated with the implementation of the

low emitter option could be as high as: $\$89,500 - \$12,500 = \$77,000 * 207 \text{ units} = \$15,939,000/\text{yr}$ if LME is used instead of Hg CEMS. Alternatively, if LME is used instead of sorbent traps, the potential savings could be even higher: $\$113,000 - \$12,500 = \$100,500 * 207 \text{ units} = \$20,803,500/\text{yr}$. This is achieved without losing the environmental integrity of the program or compromising the cap, because the default Hg concentration values used for reporting are conservatively high, and for units with FGD systems or add-on Hg emission controls, the rule requires the maximum potential concentration (MPC) to be reported when the controls are not operating properly.

As a further justification of the 5 percent low emitter threshold for Hg, EPA notes that there are two important differences between the Hg LME provisions in 40 CFR 75.81 and the LME provisions in 40 CFR 75.19 for SO₂ and NO_x (which are based on a 1 percent threshold). First, under 40 CFR 75.19, default emission rates are used exclusively, and there is no real-time continuous monitoring of the SO₂ or NO_x emissions. However, under 40 CFR 75.81, the stack gas volumetric flow rate, which is used in the hourly Hg mass emission calculations, is continuously monitored. Second, the LME provisions in 40 CFR 75.19 allow sources to either use generic default NO_x emission rates without performing any emission testing, or, if you test for NO_x, you are only required to determine a new default emission rate once every

5 years. Under 40 CFR 75.81, emission testing is required initially to qualify as a low emitter, and retesting is required either semiannually or annually thereafter, depending on the annual emission level.

3. Missing Data

To address missing data from Hg CEMS, EPA proposed to add a new section to the rule, 40 CFR 75.38, which would require the same initial and standard missing data routines that are used for SO₂ monitors to be applied to Hg CEMS. That is, until 720 hours of quality-assured Hg data have been collected following initial certification, the substitute data value for any period of missing data would be the average of the Hg concentrations recorded before and after the missing data period. Thereafter, the percent monitor data availability (PMA) would be calculated hour-by-hour, and the familiar four-tiered standard missing data procedures of 40 CFR 75.33(b) would be applied. Using this approach, the substitute data values would become increasingly conservative as the PMA decreases and the length of the missing data period increases. For PMA values below 80 percent, the MPC would be reported.

For a unit equipped with an FGD system that meaningfully reduces the concentration of Hg emitted to the atmosphere, or for a unit equipped with add-on Hg emission controls, the initial and standard Hg missing data procedures would apply only when the FGD or add-on controls

are documented to be operating properly, in accordance with 40 CFR 75.58(b)(3). For any hour in which the FGD or add-on controls are not operating properly, the MPC would be the required substitute data value.

Also for units equipped with FGD systems or add-on Hg emission controls, proposed 40 CFR 75.38 would allow the owner or operator to petition to use the maximum *controlled* Hg concentration or emission rate in the 720-hour missing data lookback (in lieu of the maximum *recorded* value) when the PMA is less than 90.0 percent.

EPA considered using the load-based NO_x missing data routines in 40 CFR 75.33(c) as the model for Hg, but this approach was not proposed in the absence of any data indicating that vapor phase Hg emissions are load-dependent. The Agency solicited comments on the proposed missing data approach.

EPA also proposed to add initial and standard missing data procedures for sorbent trap monitoring systems, in a new section, 40 CFR 75.39. Missing data substitution would be required whenever a gas sample is not extracted from the stack, or when the results of the Hg analyses representing a particular period of unit operation are missing or invalid.

The initial missing data procedures for sorbent trap systems would be applied from the hour of certification until 720 quality-assured hours of data have been collected. The initial missing data algorithm would require the owner

or operator to average the Hg concentrations from all valid sorbent trap analyses to date, including data from the initial certification test runs, and to fill in this average concentration for each hour of the missing data period.

Once 720 quality-assured hours of Hg concentration data were collected, the owner or operator would begin reporting the PMA and would begin using the standard missing data algorithms. The standard missing data procedures for sorbent trap systems would also follow a "tiered" approach, based on the PMA. For example, at high PMA (greater than or equal to 95.0 percent), the substitute data value would be the average Hg concentration obtained from all valid sorbent trap analyses in the previous 12 months. At lower PMA values, the substitute data values would become increasingly conservative, until finally, if the PMA dropped below 80.0 percent, the MPC would be reported.

Similar to the proposed provision for Hg CEMS, if a unit using sorbent traps is equipped with an FGD system or add-on Hg emission controls, the initial and standard missing data procedures could only be applied for hours in which proper operation of the emission controls is documented. In the absence of such documentation, the MPC would be reported.

Several commenters stated that the proposed missing data procedures seem to be unduly harsh and appear to be unfairly biased against the use of the sorbent trap method.

The commenters indicated that the missing data routines should properly consider the uncertainties associated with Hg monitoring, i.e., there is a lack of evidence that high PMA is achievable with these monitoring systems. Other commenters suggested that EPA should remove the MPC provision altogether for Hg monitors and fill in all missing data periods using average concentrations until more confidence is gained in the reliability of Hg monitors.

Today's final rule retains the proposed missing data provisions for Hg CEMS, but slightly relaxes the PMA cut-points. In the proposed four-tiered missing data procedure the cut points separating the tiers are at 95 percent, 90 percent, and 80 percent PMA. The final rule lowers these to 90 percent, 80 percent, and 70 percent PMA, respectively for Hg concentration monitors. The final rule also retains the MPC concept, and amends the proposed missing data procedures for sorbent traps to more closely match the Hg CEMS missing data procedures.

The final rule retains the basic missing data substitution approach for Hg that was proposed. This approach has worked well in the Acid Rain and NO_x Budget Programs. The conservative nature of the missing data routines has provided a strong incentive to sources to keep their monitoring systems operating and well-maintained. However, the PMA cut points in the final rule have been loosened slightly to account for the present lack of long-

term Hg monitoring experience in the U.S. The Agency will continue to collect and analyze CEMS and sorbent trap data from various field demonstration projects and will evaluate the performance of certified Hg CEMS operating on similar source categories (e.g., waste combustors). If the data indicate that the PMA cut-points should be changed for Hg CEMS or sorbent traps, the Agency will initiate a rulemaking for that purpose.

The suggestion to remove the MPC provisions and to fill in all missing data periods using average concentrations until EPA develops better procedures was not incorporated in the final rule for two reasons. First, when add-on emission controls that reduce Hg emissions either malfunction and are taken off-line, uncontrolled Hg emissions will result. If the Hg CEMS or sorbent trap system is out-of-control during the control device outage, an appropriate substitute data value must be used to represent uncontrolled Hg emissions and provide an incentive to fix the Hg monitoring system. The MPC concept has successfully been used in the Acid Rain and NO_x Budget Programs.

Second, EPA does not agree with the commenters that using the MPC for certain missing data periods is always unduly harsh or punitive. For the initial Hg MPC determination, the March 16, 2004 SNPR provided three options: (1) use a coal-specific default value; or (2) perform site-specific emission testing upstream of any

control device; or (3) base the MPC on 720 hours or more of historical CEMS data on uncontrolled Hg emissions. The Agency believes that these options provide adequate opportunity for affected units to develop appropriate MPC values.

Regarding the missing data routines for sorbent trap systems, available field test data have indicated that these systems are capable of performance that is equivalent to a CEMS. In view of this, EPA believes that sorbent traps should be treated on a more equal footing with Hg CEMS in many areas, including the missing data provisions.

Finally, EPA notes that a new missing data policy has been posted on the CAMD web site. The policy allows the four-tiered missing data algorithms to be applied hour-by-hour, in a stepwise manner, based on the PMA. Previously, the Agency's policy had been to determine the PMA at the end of the missing data period and to apply a single substitute data value (sometimes the MPC, if the ending PMA was less than 80 percent) to each hour in the missing data block. This new, more lenient interpretation of the 40 CFR part 75 missing data requirements will result in more representative missing data substitution and minimize the use of the MPC.

4. Instrumental Reference Method for Hg.

Only a wet chemistry method, the Ontario-Hydro Method, was proposed to perform RATAs of Hg CEMS and sorbent trap monitoring systems.

Some commenters objected to the use of the Ontario-Hydro Method for RATA testing, stating that due to the complexity of wet chemical methods and their inability to produce accurate concentrations, there will be some cases where a properly functioning Hg CEMS will fail a RATA due to inaccuracies in the reference method. Other commenters noted that unlike the instrumental reference methods routinely used to quality assure SO₂ and NO_x CEMS, the Ontario-Hydro Method can take days to complete and weeks for the return of test results from the laboratory, which could lead to significant implementation problems with respect to missing data and requirements to calculate and report data. A number of commenters stated that for applications where Hg CEMS are used, a real time instrumental reference method for RATAs is needed, and that EPA should develop such an instrumental method.

40 CFR 75.22 of the final rule allows the use of an instrumental method for RATAs of Hg monitoring systems and sorbent trap systems, subject to approval by the Administrator. EPA will propose a Hg instrumental reference method once sufficient field test data are collected and analyzed.

At present, EPA is conducting field demonstrations of Hg monitoring technology. One of the high priority items in these studies is the development of a suitable instrumental method for Hg. When the field testing is complete, EPA

intends to propose and promulgate the instrumental method. A Hg instrumental reference method for RATA testing is vastly preferable to the Ontario-Hydro Method and will greatly facilitate the implementation of a Hg cap-and-trade program. The Ontario-Hydro Method, which is a wet chemistry method that uses numerous glass impingers, requires at least a one week turn-around to obtain results, and (as with all wet chemistry methods) is cumbersome to use and subject to operator error.

5. Quality Assurance and Quality Control (QA/QC) Procedures for Hg CEMS.

For initial certification, EPA proposed to require the following tests for Hg CEMS:

- A 7-day calibration error test, using elemental Hg calibration gas standards. The monitor would be required to meet a performance specification of 5.0 percent of span on each day of the test or (for span values of 10 $\mu\text{g}/\text{scm}$) an alternate specification of 1.0 $\mu\text{g}/\text{scm}$ absolute difference between reference gas and CEMS;
- A 3-point linearity check, using elemental Hg calibration gas standards. The monitor would be required to meet a performance specification of 10.0 percent of the reference gas concentration at each gas level or an alternate specification of 1.0 $\mu\text{g}/\text{scm}$ absolute difference between reference

gas and CEMS;

- A cycle time test. The maximum allowable cycle time would be 15 minutes;
- A RATA, using the Ontario-Hydro Method. The monitor would be required to achieve a relative accuracy of 20.0 percent. Alternatively, if the Hg concentration during the RATA is less than 5.0 $\mu\text{g}/\text{scm}$, the results would be acceptable if the mean difference between the reference method does not exceed 1.0 $\mu\text{g}/\text{scm}$.
- A bias test, using data from the RATA, to ensure that the CEMS is not biased low with respect to the reference method.
- A 3-point converter check, using mercuric chloride (HgCl_2) standards. The monitor would be required to meet a performance specification of 5.0 percent of span at each gas level.

For ongoing QA/QC, we proposed the following QA/QC tests:

- Daily 2-point calibration error checks, using elemental Hg gas standards. The monitor would be required to meet a performance specification of 7.5 percent of span or an alternate specification of 1.5 $\mu\text{g}/\text{scm}$ absolute difference between reference gas and CEMS;
- Quarterly 3-point linearity checks, using

elemental Hg gas standards. The performance specifications would be the same as for initial certification.

- Monthly 3-point converter checks using HgCl₂ standards. The performance specifications would be the same as for initial certification.
- Annual RATA and bias test. The performance specifications would be the same as for initial certification.

After reviewing the proposed rule, commenters were in general agreement on the following points. Although many vendors of Hg CEMS have recently upgraded their instrument systems and these changes should eventually improve the accuracy and reliability of Hg CEMS and reduce the labor needed for instrument maintenance, these new instrument systems have not been tested extensively in demonstration programs. Therefore, the ability of these instrument systems to achieve the proposed relative accuracy, calibration error, and calibration precision requirements has not been adequately demonstrated. Therefore, EPA does not yet have a basis or data to guide the setting of specifications for calibration error, linearity, or RA. It appears that the proposed performance specifications mirror those for SO₂ and NO_x monitoring. EPA should commit to collecting data and evaluating these specifications as soon as calibration gases are available, so that the

specifications can be adjusted if necessary, prior to program implementation. EPA should require operators of Hg CEMS to conduct procedures that include but are not necessarily limited to daily zero and span audits, quarterly RA tests and three-point elemental Hg linearity tests, and absolute calibration audits. Analytically, there is clearly a need to challenge the entire system often with a form of oxidized Hg. This Hg chloride reference gas would be highly desirable to check integrity of the sample interface. However, further research needs to be required to enable the development of an accurate oxidized Hg standard. One device, the HOVACAL, may have the potential of delivering known concentrations of HgCl_2 . EPA should recognize and accept this type of calibration system in the proposed regulation. There are concerns with the proposed RATA process, particularly the length of time and amount of money that may be required to comply with the Hg monitoring requirements on an annual basis. The final monitoring requirements must be technically achievable and capable of measuring Hg emissions with precision, reliability, and accuracy in a cost-effective manner. The decision to report Hg concentration on dry or wet basis needs more consideration, as well as, the evaluation of gaseous interferences. Lastly, many of the equations and calculations are incomplete or contain errors and many sections need further clarification.

After considering the comments received, the Agency decided to retain in the final rule, the same tests as were required for initial certification and on-going QA of Hg CEMS in the SNPR. However, note the following changes to some of the procedures and performance specifications:

- For the 7-day calibration error test, either elemental Hg standards or a NIST-traceable source of oxidized Hg (referred to as "HgCl₂ standards" in the SNPR) may be used;
- Quarterly 3-level "system integrity checks" (which were called "converter checks" in the SNPR) using a NIST-traceable source of oxidized Hg may be performed in lieu of the quarterly linearity checks with elemental Hg;
- Daily calibration error checks may be performed using either elemental Hg standards or a NIST-traceable source of oxidized Hg. The daily performance specification has been made the same as for the 7-day calibration error test;
- The monthly converter check at three points has been replaced with a weekly system integrity check at a single point, and the weekly test is not required if daily calibrations are performed with a NIST-traceable source of oxidized Hg.
- When the Ontario-Hydro Method is used, paired trains are required, the results must agree within

10 percent of the relative standard deviation (RSD), and the results should be averaged.

Note that EPA plans to analyze RATA data from Hg monitors and may initiate a future rulemaking to adjust the RA performance specifications and to propose a performance-based RATA incentive system similar to the reduced frequency incentive system in 40 CFR part 75 for SO₂, NO_x, CO₂, and flow monitors.

EPA disagrees with the commenters who stated that there are no data available to justify the proposed performance specifications for Hg monitors. Such data have been collected from several field test sites and for several different types of Hg concentration monitors, which show that Hg CEMS can meet the proposed calibration error and linearity standards, and can meet a 20 percent RA standard. A more detailed discussion of these studies is provided in the Response to Comments document. Therefore, except for the daily calibration error specification, which has been tightened based on the available data, today's final rule promulgates the proposed calibration error, linearity check, and RATA performance specifications, as proposed.

EPA has retained the requirement to check the converter periodically with HgCl₂ standards, because it is essential to ensure that all of the vapor phase Hg is being measured. The frequency of the check (which is referred to as a "system integrity check" in the final rule) has been

increased from monthly to weekly, based on supportive comments to check the entire system more often, but the requirement to perform a 3-point check has been reduced to a single-point test. And the weekly test is not required if a NIST-traceable oxidized Hg source is used for daily calibrations.

There are several different devices available that can provide oxidized Hg, including the HOVACAL and the MerCAL. The HOVACAL has been successfully applied in the laboratory and field to generate and deliver known concentrations of HgCl₂ to Hg CEMS to achieve the requirements of the 40 CFR part 75 system integrity check. Moreover, oxidized Hg gas standards such as are produced by the HOVACAL and MerCAL are currently scheduled to be independently tested by NIST, to verify their suitability as reference gas standards.

6. Sorbent Trap Operation and QA/QC.

General guidelines for operating sorbent trap systems were proposed in 40 CFR 75.15. The use of paired traps would be required, and the stack gas would be sampled at a rate that is proportional to the stack gas volumetric flow rate. Proposed Method 324 would be used as the protocol for operating the monitoring systems and for analyzing the Hg samples collected by the sorbent traps.

Additional QA requirements for sorbent trap systems were proposed in sections 1.5, 2.3 and 2.7 of 40 CFR part 75, appendix B. Development of a QA/QC program and plan

would be required. Key components of this program would be assignment of permanent identification (ID) numbers to the sorbent traps, keeping of records of the dates and times that each trap is used, establishment of a chain of custody for transporting and analyzing the traps, documentation that the laboratory analyzing the samples is certified according to International Organization for Standardization (ISO) 9000 standards, explanations of the leak check and other QA test procedures, and the rationale for the minimum acceptable data collection time for each trap. In addition, the data acceptance and QC criteria of proposed Method 324 would be included in the QA plan.

An annual RATA and bias test of each sorbent trap system would be required, using the Ontario-Hydro Method as the reference method. And if proposed Alternative #2 were implemented (i.e., allowing sorbent trap systems to be used by any affected unit), for units with annual Hg mass emissions above a certain threshold value (we took comment on four thresholds, i.e., 9 lb/hr, 29 lb/hr, 46 lb/hr, and 76 lb/hr), additional 3-run RAAs would be required in the other three quarters of the year.

The commenters were generally opposed to the proposed quarterly RAAs for sorbent trap systems as being too costly and of little value. A number of commenters suggested that EPA should revise proposed Alternative #2 and specify quality assurance procedures that are meaningful to the type

of measurement system that the sorbent trap actually is. For example, the volume of stack gas sampled by the system is an important parameter in determining the Hg concentration. Therefore, procedures for quality-assuring the measurement of the sample volume could be implemented.

Some commenters favored allowing the use of proposed Method 324 for all affected units, and stated that because proposed Method 324 is itself a test method, it does not need additional QA procedures. Two commenters suggested that EPA should even take steps to make proposed Method 324 a reference method. However, numerous other commenters objected to various provisions of proposed Method 324 and offered suggestions for improving it. Some of the chief objections raised were as follows:

- The allowable analytical techniques and procedures in the method are too exclusive, and in the case of Method 1631, inappropriate. Other analytical methodologies should be allowed;
- The impinger and dessicant method of moisture removal is inadequate;
- The leakage rate prescribed for the leak checks may be too low to measure;
- The method allows constant-rate sampling for collection periods less than 12 hours, which may introduce bias if unit load changes during the collection period;

- The specification for flow proportional sampling (adjust sample flow rate to maintain proportional sampling within \pm 25 percent of stack gas flow rate) is not stringent enough and can lead to inaccurate concentration measurement;
- The frequency for dry gas meter calibration is unspecified; and
- The method does not include chain of custody procedures.

A number of commenters suggested that EPA should not require the use of paired sorbent traps and should allow the use of single sorbent traps.

Several commenters objected to the proposal in section 1.5.4 of Appendix B that laboratories performing proposed Method 324 be certified by the ISO to have proficiency that meets the requirements of ISO 9000. One commenter stated that having a good blank and matrix spike program in place is much more indicative of a good QA/QC program for Hg measurement than ISO 9000 certification. Another commenter favored ISO certification, but not according to ISO 9000. The commenter recommended that ISO 17025 be required instead, because it requires the laboratory to demonstrate proficiency, rather than simply having an acceptable protocol for the analyses.

One commenter stated that EPA has not explained the appropriateness of applying a bias test and adjustment

factor to proposed Method 324, when it has already satisfied the same standards for bias and precision as the Ontario-Hydro Method under EPA Method 301. Another commenter suggested that it does not make sense to subject Hg monitors to a bias adjustment factor under Appendix A, section 7.6 when paired reference method trains are allowed to differ by 10 percent RSD, based on a flawed definition of RSD. The commenter asserted that it is not reasonable to suggest that a Hg monitor is biased by comparing its readings to a pair of reference method tests that can differ by 20 percent.

In view of the many comments received regarding a large number of testing and QA provisions in proposed Method 324, EPA has decided to revise and rename proposed Method 324 as 40 CFR part 75, appendix K in the final rule. Based on comments received and experience gained from field tests since proposal, appendix K retains certain provisions and revises others in proposed Method 324 to include detailed, performance-based criteria, QA standards and procedures for sorbent trap monitoring systems. Today's rule also revises both the definition of a sorbent trap monitoring system in section 72.2 and the general guidelines for sorbent trap monitoring system operation in 40 CFR 75.15, to be consistent with the requirements of 40 CFR part 75, appendix K.

The final rule retains the annual RATA and bias test requirements for sorbent trap monitoring systems, but the

proposed quarterly RAA requirement has been withdrawn. The requirements to use paired traps and flow proportional sampling have also been retained. Finally, the ISO 9000 certification requirement for the laboratory performing the Hg analyses has been replaced with a requirement for the laboratory to either comply with ISO-17025 or to comply initially, and annually thereafter, with the spike recovery study provision in Section 10 of 40 CFR part 75, appendix K.

Several commenters recommended that EPA should require QA procedures for sorbent traps that are more meaningful and reasonable than the procedures in the SNPR. EPA agrees with these comments, and based on the recommendations received, today's rule specifies such procedures in Appendix K. Many provisions of proposed Method 324 have been included in Appendix K without modification, but other provisions of the proposed Method have been modified to employ a more performance-based approach and some new QA procedures have been added to address concerns expressed by the commenters. Some of the more significant differences between proposed Method 324 and Appendix K are as follows:

- Appendix K allows the use of any sample recovery and analytical methods that are capable of quantifying the total vapor phase Hg collected on the sorbent media. Candidate recovery techniques include leaching, digestion, and thermal desorption. Candidate analytical techniques

include ultraviolet atomic fluorescence (UV AF), ultraviolet atomic absorption (UV AA), and in-situ X-ray fluorescence (XRF);

- Appendix K requires that each sorbent trap be comprised of three equal sections, capable of being separately analyzed. The first section is for sample collection, the second to assess "breakthrough", and the third to allow spiking with elemental Hg for QA purposes;
- Appendix K specifies the frequency of dry gas meter calibration and the appropriate calibration procedures;
- Appendix K requires ASTM sample handling and chain of custody procedures to be followed;
- Spiking of the third section of each trap with elemental Hg is required before the data collection period begins;
- The laboratory performing the analyses must demonstrate the ability to recover and quantify Hg from the sorbent media; and
- The measured Hg mass in the first and second sections of each trap is adjusted, based on the percent recovery of Hg from the third ("spiked") section.

EPA believes that if these procedures are implemented, this will ensure the quality of the data from sorbent trap

systems.

Today's final rule retains the requirement to use paired sorbent traps. The SNPR proposed the use of paired sorbent traps for the same basic reason that paired Ontario-Hydro traps are required for RATA testing, i.e., it provides an important check on the quality of the data. The proposed rule would have required the higher of the two Hg concentrations obtained from the paired traps to be used for reporting. However, the final rule requires the results from the two traps to be averaged if paired concentrations agree within specified criteria, and allows the results from one trap (if those results are valid) to be reported in cases where the other trap is accidentally damaged, broken or lost during transport and analysis. Thus, using paired sorbent traps provides a relatively inexpensive means of ensure against data loss should one of the traps become lost or damaged.

The commenters generally objected to the proposed quarterly relative accuracy testing of sorbent traps, believing it to be unnecessary and costly. After consideration of recent field data comparing the sorbent traps to Hg CEMS, EPA agrees that sorbent trap systems should be treated more similarly to Hg CEMS. Therefore, today's final rule removes the quarterly RAA requirement, and requires only that an annual RATA be performed on a sorbent trap monitoring system.

One commenter objected to the proposed bias test requirement for sorbent trap systems, citing the fact that proposed Method 324 had satisfied the same standards for bias and precision as the Ontario-Hydro Method under EPA Method 301. EPA does not agree with this comment. The fact that proposed Method 324 met the bias and precision requirements of Method 301 does not imply that Hg sorbent traps will not exhibit low bias with respect to a Hg reference method during a RATA. The bias test in section 7.6 of 40 CFR part 75, appendix A is a one-tailed t-test, which, if failed, requires a bias adjustment factor (BAF) to be applied to the subsequent emissions data.

EPA also does not agree with the commenter who stated that bias adjustment is not appropriate for sorbent trap systems because of the allowable 10 percent RSD between the paired reference method trains. The 40 CFR part 75 bias test determines systematic error, not random error, whereas RSD and relative accuracy are metrics used to quantify random error in the measurement.

7. Mercury-Diluent Systems.

Mercury-diluent monitoring systems (consisting of a Hg pollutant concentration monitor, an O₂ or CO₂ diluent gas monitor, and an automated data acquisition and handling system) to measure Hg emission rate in lb/10¹² Btu were allowed in the proposed rule.

One commenter asked why the proposed Hg emissions units

of measurement are the same as NO_x-diluent? The Hg concentration measurements are orders of magnitude below NO_x emissions, thus applying a diluent correction with the additional uncertainties of measurement further complicates the direct emissions reporting uncertainties. Mercury is a resident pollutant in the fuel, it can be measured, and measurement should parallel the same regulation requirements as SO₂.

Today's final rule removes all mention of Hg-diluent monitoring systems and requires the hourly Hg mass emissions to be calculated in the same manner as is done for SO₂ under the Acid Rain Program, i.e., as the product of the Hg concentration and the stack gas flow rate. The final rule also better accommodates Hg analyzers that measure on a wet basis.

EPA believes that the rule can be considerably simplified and shortened without losing any flexibility by deleting the provisions related to Hg-diluent monitoring systems and allowing only Hg concentration monitoring systems and sorbent trap systems to be used. Therefore, today's final rule removes all mention of Hg-diluent monitoring systems and requires the hourly Hg mass emissions to be calculated in the same manner as is done for SO₂, i.e., as the product of the Hg concentration and the stack gas flow rate.

G. Impact estimates

1. IPM Modeling
 2. Health
 3. Environmental impacts
 4. Costs and economic impacts
- H. Compliance with Executive Orders and statutes (OAQPS - ISEG)**
1. Regulatory impact analysis (E.O. 12866, Analysis of alternatives, benefits, health costs)
 2. Indian Tribes (Consultations, unique impacts, and risks)
 3. FACA
 4. Children's health (E.O. 13045)
 5. Unfunded mandates
 6. Energy effects
 7. Environmental justice
 8. Data quality
- I. Alternative regulatory approaches**
- J. Other**
1. Initial Report to Congress
 2. Need for additional control
 3. Other Hg sources
 4. Stakeholder influence
 5. Procedural issues
- V. Summary of the Environmental, Energy, Cost, and Economic Impacts (OAQPS - ISEG)**
- A. What are the air quality impacts?**

B. What are the non-air health, environmental, and energy impacts?

C. What are the cost and economic impacts?

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether a regulatory action is "significant" and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The 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.

In view of its important policy implications and

potential effect on the economy of over \$100 million, this action has been judged to be an economically "significant regulatory action" within the meaning of the Executive Order. As a result, today's action was submitted to OMB for review, and EPA has prepared an economic analysis of the rule entitled "Regulatory Impact Analysis of the Final Clean Air Mercury Rule" (March 2005).

CAMR builds upon the findings of the National Energy Policy Development Group; to provide reliable, affordable, and environmentally sound energy for America's future (<http://www.whitehouse.gov/energy>). Recognizing the need for an integrated approach to environmental, energy, and economic policy, CAMR is an example of environmental regulation that recognizes and balances the need for energy diversity, reliability, and affordability.

1. What economic analyses were conducted for the rulemaking?

The analyses conducted for this final rule provide several important analyses of impacts on public welfare. These include an analysis of the social benefits, social costs, and net benefits of the regulatory scenario. The economic analyses also address issues involving small business impacts, unfunded mandates (including impacts for Tribal governments), environmental justice, children's health, energy impacts, and requirements of the Paperwork Reduction Act (PRA).

2. What are the benefits and costs of this rule?

[Placeholder]

a. Control scenario.

The final CAMR requires annual Hg reductions for the power sector in 50 states, the District of Columbia, and two Tribes. EPA considered the final CAIR for SO₂ and NO_x requirements and all promulgated CAA requirements and known state actions in the baseline used to develop the estimates of benefits and costs for this rule. For a more complete description of the reduction requirements and how they were calculated, see section V of today's rulemaking.

CAMR was designed to achieve significant Hg emissions reductions from the power sector in a much more cost-effective manner than a facility-specific or unit-specific approach. EPA analysis has found that the most cost-effective method to achieve the emissions reduction targets is through a cap-and-trade system that States have the option of adopting. States, in fact, can choose not to participate in the optional cap-and-trade program. However, EPA believes that a cap-and-trade system for the power sector is the best approach for reducing Hg emissions. As a result, for purposes of analyzing the impacts of the rule, EPA is assuming the application this more cost effective approach.

b. Cost Analysis and Economic Impacts.

For today's action, EPA analyzed the costs using the

IPM. IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for Hg, SO₂, and NO_x throughout the contiguous U.S. for the entire power system. Documentation for IPM can be found in the docket for this rulemaking or at www.epa.gov/airmarkets/epa-ipm.

CAMR fulfills the commitment made in the President's National Energy Policy, which calls for environmental improvement and emission reductions from the power sector while recognizing the need to maintain energy diversity and reliability.

The projected annual costs of CAMR to the power industry are \$160 million in 2010, \$100 million in 2015, and \$750 million in 2020. These costs represent the total cost to the electricity-generating industry of reducing Hg emissions to meet the caps set forth in the rule and are incremental costs to the requirements to meet NO_x and SO₂ emissions caps set forth in the CAIR. Estimates are in 1999 dollars.

Retail electricity prices are projected to increase roughly 0.2 percent higher with CAMR in 2020 when compared to CAIR. Natural gas prices are projected to increase by roughly 1.6 percent with CAMR in 2020 when compared to CAIR. There will be continued reliance on coal-fired generation, which is projected to remain at roughly 50 percent of total electricity generated and no coal-fired capacity projected

to be uneconomic to maintain incremental to CAIR. As demand grows in the future, additional coal-fired generation is projected to be built. As a result, coal production for electricity generation is projected to increase from 2003 levels by about 13 percent in 2010 and 20 percent by 2020, and we expect a small shift towards greater coal production in Appalachia and the Interior coal regions of the country with CAMR compared to 2003.

c. Human Health and Welfare Benefit Analysis

The final CAMR will reduce emissions of Hg. The Hg emission reductions associated with implementing of the final CAMR would produce a variety of benefits. Mercury emitted from utilities and other natural and man-made sources is carried by winds through the air and eventually is deposited to water and land. In water, some Hg is transformed to methylmercury (MeHg) through biological processes. Methylmercury, a highly toxic form of Hg, is the form of Hg of concern for the purpose of this rulemaking. Once Hg has been transformed into MeHg, it can be ingested by the lower trophic level organisms where it can bioaccumulate in fish tissue (i.e., concentrations in predatory fish build up over the fish's entire lifetime, accumulating in the fish tissue as predatory fish consume other species in the food chain). Thus, fish and wildlife at the top of the food chain can have Hg concentrations that are higher than the lower species, and they can have

concentrations of Hg that are higher than the concentration found in the water body itself. Therefore, the most common form of exposure to Hg for humans and wildlife is through the consumption of Hg contained in predatory fish, such as: commercially consumed tuna, shark, or other saltwater fish species and recreationally caught bass, perch, walleye or other freshwater fish species. When humans consume fish containing MeHg, the ingested MeHg is almost completely absorbed into the blood and distributed to all tissues (including the brain); it also readily passes through the placenta to the fetus.

Some subpopulations in the U.S. (e.g., Native Americans, Southeast Asian Americans, recreational and subsistence anglers) consume larger amounts of fish than the general population and may be at a greater risk to the adverse health effects from Hg due to increased exposure. In pregnant women, MeHg can be passed on to the developing fetus, and at sufficient exposure may lead to a number of neurological effects in children. Thus, children who are exposed to low concentrations of MeHg prenatally may be at increased risk of poor performance on neurobehavioral tests, such as those measuring attention, fine motor function, language skills, visual-spatial abilities (like drawing), and verbal memory. The effects from prenatal exposure can occur even at doses that do not result in effects in the mother. A full discussion of the neurological health

effects of Hg is provided by the National Research Council in "Neurological Effects of Methylmercury." (NRC, 2002). EPA held a workshop with several of the NRC panel members in 2002. Participants were asked about which studies should be considered in generating dose-response functions for developmental neurotoxicity. Participants were also asked about endpoints to consider for monetization and they suggested looking at neurological tests that might lead to changes in IQ or other neurodevelopmental impacts. EPA determined that IQ decrements due to Hg exposure is one endpoint that EPA should focus on for a benefit analysis, because it can be monetized. The focus population for the benefit analysis is women of childbearing age who consume freshwater, recreationally-caught fish. Methylmercury is a developmental neurotoxicant with greatest biological sensitivity from *in utero* exposure.

Three large-scale epidemiological studies have examined the effects of low dose prenatal Hg exposure and neurodevelopmental outcomes through the administration of numerous tests of cognitive functioning. These studies were conducted in the Faroe Islands (Grandjean et al. 1997), New Zealand (Kjellstrom et al. 1989, Crump et al. 1998), and the Seychelles Islands (Davidson et al. 1998, Myers et al. 2003). Based on recommendations from participants at the Hg workshop discussed above, and the ability to monetize IQ decrements, EPA combined data and information from all three

of these studies to develop a combined dose-response function for IQ decrements to apply in a benefit analysis.

In response to potential risks of consuming fish containing elevated concentrations of Hg, EPA and FDA have issued a joint fish consumption advisory which provides recommended limits on consumption of certain fish species for different populations. This joint EPA and FDA advisory recommends that women who may become pregnant, pregnant women, nursing mothers, and young children to avoid some types of fish and eat fish and shellfish that are lower in Hg, diversifying the types of fish they consume, and by checking any local advisories that may exist for local rivers and streams.

Although highly dependent on uncertain future technology choices of the industry, EPA believes that CAMR may also reduce emissions of directly emitted PM, which contribute to the formation of $PM_{2.5}$. In general, exposure to high concentrations of $PM_{2.5}$ may aggravate existing respiratory and cardiovascular disease including asthma, bronchitis and emphysema, especially in children and the elderly. It should be noted that despite declining levels of PM in the ambient air, asthma and bronchitis levels in the population seem to have increased in the past decades. Exposure to $PM_{2.5}$ can lead to decreased lung function, and alterations in lung tissue and structure and in respiratory tract defense mechanisms which may then lead to, increased

respiratory symptoms and disease, or in more severe cases, premature death or increased hospital admissions and emergency room visits. Children, the elderly, and people with cardiopulmonary disease, such as asthma, are most at risk from these health effects. $PM_{2.5}$ can also form a haze that reduces the visibility of scenic areas, can cause acidification of water bodies, and have other impacts on soil, plants, and materials.

Due to both technical and resource limits in available modeling, we have only been able to quantify and monetize the benefits for a few of the endpoints associated with reducing Hg, and directly emitted PM. In the "Regulatory Impact Analysis of the Final Clean Air Mercury Rule," we provide an analysis of the benefits from avoided IQ decrements in prenatally exposed children from the reduction of MeHg exposures and the benefits of reducing directly emitted PM.

There are several fish consumption pathways considered by the Agency for the benefit analysis, including: consumption from commercial sources (including saltwater and freshwater fish from domestic and foreign producers), consumption of commercial fish raised at fish farms (aquaculture), and consumption of recreationally caught freshwater and saltwater fish. However, technical limitations in designing an analytical approach to quantify these exposure pathways (as are discussed in the RIA) limits

the benefit analysis for CAMR to an assessment of exposures from recreational freshwater fishing activities. To model recreational angling and prenatal exposure from this consumption pathway (i.e., women of childbearing age consuming freshwater fish and, hence, exposing the fetus *in utero*), we consider two modeling approaches: one approach that estimates the distance anglers are likely to travel from their households to water bodies for fishing activities (referred to as the Population Centroid Approach), and another approach that models how often recreational anglers fish at certain locations (referred to as the Angler Destination Approach). These resulting benefits from the two exposure modeling approaches differ, however, we expected they are likely to capture the range of actual behavior (and likely exposure) of recreational anglers. In addition, the current state of knowledge of the science indicates that there is likely a lag in the time between the reduction in Hg deposition to a water body and the change in MeHg concentrations in fish tissue. Based on a review of available literature and a series of case studies conducted by EPA, the lag period for changes in fish tissue (and hence changes in avoided IQ decrements) can range from less than 5 years to more than 50 years. In the benefit analysis presented in the RIA, we present a range of results assuming a series of potential lag scenarios (including 5, 10, 20, and 50 years) on the total benefits. We also present future

year benefits discounted at a 3 percent and a 7 percent rate. In addition, due to the potential for intergenerational effects, the 50 year lag is assessed using a 1 percent discount rate as well as the 3 and 7 percent discount rates (in accordance with the EPA Economic Guidelines). Benefits are evaluated after full implementation of CAMR and presented in 1999 dollars. The resulting benefits presented in the RIA show a range of potential values based on all of these sources of variability in the estimate. Giving consideration to all of the possible outcomes discussed in the RIA, the overall benefits of CAMR range in value from approximately \$2.5 million to \$3 million.

In an analysis of the possible co-benefits associated with emission reductions of directly emitted PM, we estimated the total change in incidence of premature mortality. We conducted a screening-level analysis using a simplified air quality and exposure modeling approach (the SR Matrix) to derive a benefit transfer value (i.e., \$benefit per ton PM) that were applied to total estimate emission reductions of direct PM. The total estimated PM-related benefits range from \$[XX] to approximately \$40 million, depending on technology assumptions. However, the calculation of these benefits are subject to significant uncertainty and are therefore not included in our primary benefit estimate.

3. How do the benefits compare to the costs of this final rule?

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B. Paperwork Reduction Act

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C. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. § 601 et seq.) (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104-121) (SBREFA), provides that whenever an agency is required to publish a general notice of rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the rule, if promulgated, will not have "a significant economic impact on a substantial number of small entities." 5 U.S.C. § 605(b). Small entities include small businesses, small organizations, and small governmental jurisdictions.

As was discussed in the January 30, 2004 NPR and the March 16, 2004 SNPR, EPA determined that it was not necessary to prepare a regulatory flexibility analysis in conjunction with this rulemaking. EPA also announced in the NPR its determination that, based on analysis conducted for the proposed rule, CAMR would not have a significant impact on a substantial number of small entities. Although not required by the RFA, the Agency has conducted an additional analysis of the effects of CAMR on small entities in order

to provide additional information to States and affected sources.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) a small business that is identified by the North American Industry Classification System (NAICS) Code, as defined by the Small Business Administration (SBA); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. Categories and entities potentially regulated by this rule with applicable NAICS codes are provided in the Supplementary Information section of this action.

According to the SBA size standards for NAICS code 221122 Utilities-Fossil Fuel Electric Power Generation, a firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.

Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule. See Michigan v. EPA, 213 F.3d 663, 668-69 (D.C. Cir. 2000), cert. den. 121

S.Ct. 225, 149 L.Ed.2d 135 (2001).

This rule would not establish requirements applicable to small entities. Instead, it would require States to develop, adopt, and submit a State Plan that would achieve the necessary Hg emissions reductions, and would leave to the States the task of determining how to obtain those reductions, including which Utility Units to regulate.

EPA analysis of the final rule supports the results of earlier analysis discussed in the NPR that found that CAMR would not have a significant direct impact on a substantial number of small entities, although there could be an increase in their costs of electricity. Analysis conducted for the final rule projects that in 2020, two years into the start of the second phase of the cap-and-trade program, the total compliance costs to small entities under CAMR would be approximately \$37 million. This is just under 1 percent of the total projected electricity generation revenues to small entities for 2020. A few of the 80 small entities identified in EPA analysis may experience significant costs in 2020. These entities do not bank over the course of the program, and must purchase allowances in 2020 to cover their emissions. It is important to note that the marginal cost of Hg control in 2020 projected by EPA modeling is largely responsible for the presence of significant impacts. EPA modeling assumes no improvements in the cost or effectiveness of Hg control technology over time. In

reality, by 2020, costs of Hg control are expected to have declined, such that the actual impacts of the cap-and-trade program on small entities will be less than projected. Additionally, given that most of the small entities identified operate in market environments in which they can pass on compliance costs to consumers, most of these entities should be able to recover their costs of compliance with CAMR.

Two other points should be considered when evaluating the impact of CAMR, specifically, and cap-and-trade programs more generally, on small entities. First, under CAMR, the cap-and-trade program is designed such that States determine how Hg allowances are to be allocated across units. A State that wishes to mitigate the impact of the rule on small entities might choose to allocate Hg allowances in a manner that is favorable to small entities. Finally, the use of cap-and-trade in general will limit impacts on small entities relative to a less flexible command-and-control program.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (Public Law 104-4) (UMRA), establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under UMRA section 202, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a

cost-benefit analysis, for any proposed or final rule that "includes any Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector, of \$100,000,000 or more . . . in any one year." A "Federal mandate" is defined under section 421(6), 2 U.S.C. 658(6), to include a "Federal intergovernmental mandate" and a "Federal private sector mandate." A "Federal intergovernmental mandate," in turn, is defined to include a regulation that "would impose an enforceable duty upon State, local, or Tribal governments," section 421(5)(A)(i), 2 U.S.C. 658(5)(A)(i), except for, among other things, a duty that is "a condition of Federal assistance," section 421(5)(A)(i)(I). A "Federal private sector mandate" includes a regulation that "would impose an enforceable duty upon the private sector," with certain exceptions, section 421(7)(A), 2 U.S.C. 658(7)(A).

Before promulgating an EPA rule for which a written statement is needed under UMRA section 202, UMRA section 205, 2 U.S.C. 1535, 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 EPA prepared a written statement for the NPR consistent with the requirements of UMRA section 202. This statement was prepared in the context of the proposed

Utility MACT for Hg. Furthermore, as EPA has stated in the rule, EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments. Thus, EPA is not obligated to develop under UMRA section 203 a small government agency plan. It should also be noted that, in a manner consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA carried out consultations with the governmental entities affected by this rule.

Nonetheless, EPA has conducted an analysis of the potential economic impacts anticipated of CAMR on government-owned entities. These results support EPA's assertion in the NPR that the proposed rule would not have a disproportionate budgetary impact on government entities. Overall, analysis conducted for the final rule projects that in 2020, two years into the start of the second phase of the cap-and-trade program, compliance costs to government-owned entities would be approximately \$48 million. This cost is less than one-half of one percent of projected electricity generation revenues for these entities in 2020. A few of the 88 entities identified in EPA analysis are projected to experience significant costs in 2020. These entities do not bank over the course of the program, and must purchase allowances in 2020 to cover their emissions. As was the case in EPA's analysis of small entities, it is important to

note that the marginal cost of Hg control in 2020 projected by EPA modeling is largely responsible for the presence of significant impacts in the analysis. EPA modeling assumes no improvements in the cost or effectiveness of Hg control technology over time. In reality, by 2020, costs of Hg control are expected to have declined, such that the impacts of the cap-and-trade program on small entities would be reduced. Additionally, given that most of the small entities identified operate in market environments in which they can pass on compliance costs to consumers, most of these entities should be able to recover their costs of compliance with CAMR.

Potentially adverse impacts of CAMR on State and municipality-owned entities could be limited by the fact that the cap-and-trade program is designed such that States determine how Hg allowances are to be allocated across units. A State that wishes to mitigate the impact of the rule on State or municipality-owned entities might choose to allocate Hg allowances in a manner that is favorable to these entities. Finally, the use of cap-and-trade in general will limit impacts on entities owned by small governments relative to a less flexible command-and-control program.

E. Executive Order 13132: Federalism

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F. Executive Order 13175: Consultation and Coordination

with Indian Tribal Governments

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

[Placeholder]

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

Executive Order 13211 (66 FR 28355, May 22, 2001)

provides that agencies shall prepare and submit to the Administrator of the Office of Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as "significant energy actions." Section 4(b) of EO 13211 defines "significant energy actions" as "any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of final rulemaking, and notices of final rulemaking: (1) (i) That is a significant regulatory action under EO 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a "significant energy action."

Although this final rule is a significant regulatory action under EO 12866, this rule likely will not have a significant

adverse effect on the supply, distribution, or use of energy.

In May 2001, the Administration published the NEP which contained key recommendations for improving energy policy. CAMR, in conjunction with CAIR, has the potential to require installation of significant amounts of control equipment at power plants that are integral to the country's electric power supply, and, in light of this, EPA has focused on minimizing the impacts of CAMR throughout the development of the rule in keeping with the NEP. The rule follows the recommendations of the NEP to use cost-effectiveness and market-based mechanisms while providing regulatory certainty and sufficient time to achieve reductions of Hg emissions from the power sector in a way that will help the country maintain electric reliability and affordability while ensuring environmental goals are met. In addition, Hg reductions have been coordinated with the CAIR rulemaking, with the first phase reductions set at a cap level that reflects the Hg reductions that would be achieved from the SO₂ and NO_x cap levels under CAIR. Although the stated recommendation of the Administration's energy plan was to adopt multi-pollutant legislation, like the Clear Skies Act, EPA has acted in accordance with the CAA to ensure substantial reduction of pollution to protect human health and welfare, consistent with the NEP.

EPA has conducted the analysis of this rulemaking

assuming States participate in a cap-and-trade program to reduce emissions from Utility Units. EPA does not believe that this rule will have any impacts incremental to CAIR that exceed the significance criteria, because it does not have a greater than a 1 percent impact on the cost of electricity production and it does not result in the retirement of greater than 500 MW of coal-fired generation.

In addition, the EPA believes that a number of features of today's rulemaking serve to reduce its impact on energy supply. First, the optional trading program provides considerable flexibility to the power sector and enables industry to comply with the emission reduction requirements in the most cost-effective manner, thus minimizing overall costs and the ultimate impact on energy supply. The ability to use banked allowances from the first phase of the program also provides additional flexibility. Second, the CAMR caps are set in two phases, provide adequate time for Utility Units to install pollution controls, and Hg reductions have been coordinated with the CAIR rulemaking, with the first phase reductions set at a cap level that reflects the Hg reductions that would be achieved from the SO₂ and NO_x cap levels under CAIR.

For more details concerning energy impacts, see Regulatory Impact Analysis for the Final Clean Air Mercury Rule (March 2004)[**Insert docket number**].

I. National Technology Transfer and Advancement Act

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J. Congressional Review Act

[Placeholder]

List of Subjects

40 CFR part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Coal, Electric power plants, Intergovernmental relations, Metals, Natural gas, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides

40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Reporting and recordkeeping requirements.

Dated: March 15, 2005.

Stephen Johnson,
Acting Administrator