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 (ounce) 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 (SO_2) 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 SO_2 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 SO_2 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 SO_2 and NO_x. Significant Hg emissions reductions can be obtained as a “co-benefit” of controlling emissions of SO_2 and NO_x; thus, the coordinated regulation of Hg, SO_2, 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 40 CFR part 75, appendix K, “Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems.”

The EPA is today also taking final action to amend the definition of “designated pollutant” in 40 CFR 60.21(a). The existing definition predates the Clean Air Act Amendments of 1990 (the CAAA) and, as a result, refers to section 112(b)(1)(A) which no longer exists. The EPA is also amending the definition of “designated pollutant” so that it conforms to EPA’s interpretation of the provisions of section 111(d)(1)(A) of the Act, as amended by the CAAA. That interpretation is explained in detail in a separate Federal Register notice announcing EPA’s revision of its December 2000 regulatory determination and removing Utility Units from the 112(c) list of categories. For these reasons, EPA has determined that it is appropriate to promulgate the revised definition of “designated pollutant” without prior notice and opportunity for comment.

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 legacy docket are listed in the legacy docket index available through the Air and Radiation Docket; all documents in the EDOCKET are listed in the EDOCKET index at http://www.epa.gov/edocket. Although listed in the indices, 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 EDOCKET Internet site 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 the final rule 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.

Category	NAICS code[1]	Examples of potentially regulated entities
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.

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[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 the final rule. This table lists examples of the types of entities EPA is now aware could potentially be regulated by the final rule. Other types of entities not listed could also be affected. To determine whether your facility, company, business, organization, etc., is regulated by the final rule, you should examine the applicability criteria in 40 CFR 60.45a of the final NSPS amendments. If you have questions regarding the applicability of the final rule 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 rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

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

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I. National Technology Transfer and Advancement Act
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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.” (See 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.” (See CAA §110(b)(1)(A).) EPA must then set federal standards of performance for new sources within each listed source category. (See 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. (See 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. (See CAA §111(d)(1).) Section 111(d) authorizes EPA to promulgate standards of performance that States must adopt through a State Implementation Plans (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. (See 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 <u>Federal Register</u> 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 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

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[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.

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 Response to “Significant Public Comments on the Proposed Clean Air Mercury Rule,” 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 (EO) 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. Comments received after the close of the public comment period on the NODA (January 3, 2005), were not considered in the analyses. 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). In that action, 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.

In a separate Federal Register document, 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 SO_2, NO_x, and particulate matter (PM) were proposed under CAA section 111 for Utility Units (40 CFR part 60, subpart Da) and industrial boilers (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

In a separately published action, 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 CAA section 112(c) source category list. Section 112(n)(1)(A) of the CAA is the threshold statutory provision underlying the action. That provision requires EPA to conduct a study to examine the hazards to public health that are reasonably anticipated to occur as the result of HAP emissions from Utility Units after imposition of the requirements of the CAA. The provision also provides that EPA shall regulate Utility Units under CAA 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 light of the finding, EPA in December 2000 announced its decision to list coal- and oil-fired Utility Units on the CAA section 112(c) list of regulated source categories. 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 CAA section 112(c) list.

By a separately published action, we are revising the December 2000 appropriate and necessary finding and concluding that it is neither appropriate nor necessary to regulate coal- and oil-fired Utility Units under CAA 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 CAA section 112. Based solely on the revised finding, we are removing coal- and oil-fired Utility Units from the CAA section 112(c) list. The reasons supporting today's action are described in detail in the separately published action.

EPA is revising its December 2000 determination and removing coal- and oil-fired Utility Units from the CAA section 112(c) source category list because we have concluded that utility HAP emissions remaining after implementation of other requirements of the Act, including in particular the CAIR, do not cause "hazards to public health" that would warrant regulation under CAA section 112.

The HAP of greatest concern from coal-fired utilities is Hg. Although we believe that after implementation of CAIR, remaining utility emissions will not pose hazards to public health, we do believe that it is appropriate to establish national, uniform Hg emission standards for new and modified coal-fired utilities, as defined elsewhere in this preamble. Effective controls have been adequately demonstrated to reduce utility emissions; such reductions will further the goal of reducing the domestic and global Hg pool.

Under the structure of the CAA, once we establish NSPS for new sources under section 111(b), we must, with respect to designated pollutants, establish 111(d) standards for existing sources. Specifically, section 111(d) provides that the Administrator “shall prescribe regulations which establish a procedure under which each State shall submit . . . a plan which establishes standards of performance for any existing source for any air pollutant . . . to which a standard of performance under this section would apply if such existing source were a new source.” Thus, since we deem it appropriate to establish NSPS for Hg emissions from new sources, we are obligated to establish NSPS Hg standards for existing sources as well.

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, SO_2, 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 the final rule.

D. What are the emission limitations and work practice

standards?

The following standards of performance for Hg are being finalized in the final rule for new coal-fired 40 CFR part 60, subpart Da units:

Bituminous units:	0.0026 nanograms per joule (ng/J)(21 x 10^{-6} lb/megawatt-hour (lb/MWh));
Subbituminous units:	
Wet FGD	0.0055 ng/J (42 x 10^{-6} lb/MWh);
Dry FGD	0.0103 ng/J (78 x 10^{-6} lb/MWh);
Lignite units:	0.0183 ng/J (145 x 10^{-6} lb/MWh);
Coal refuse units:	0.00017 ng/J (1.4 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 the final rule. 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 (QA) techniques; and recordkeeping and reporting procedures. The final amendments require 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 QC of the Hg CEMS, the final rule 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 relative accuracy test audit (RATA) and three measurement error tests (as described in PS 12-A), using $HgCl_2$ standards. In lieu of implementing the 40 CFR part 60, appendix F procedures, the owner or operator may QA the data from the Hg CEMS according to 40 CFR part 75, appendix B. For sorbent trap monitoring systems, and annual RATA is required, and the on-going 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 the final rule.

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

The final rule 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 40 CFR part 60, 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 the final rule, 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. A coal-fired Utility Unit is a unit 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.

For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, 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 during the 12-month period 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 definition starting on the day on which the unit first no longer qualifies as a cogeneration unit. These criteria are similar to the definition in the NPR and SNPR 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 significant increases in maintenance costs. 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 the final rule 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 rule 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 non-air quality health and environmental impacts and energy requirements), the Administrator determines has been adequately demonstrated.” (See 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.” (See CAA §111(b)(1)(A).) EPA must then set Federal standards of performance for new sources within each listed source category. (See 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. (See 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 SO_2. 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 anticipates will be implemented and will reduce 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 non-catalytic reduction (SCR) system in conjunction with one of these systems 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, on the other hand, 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. Available information indicates that 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. After considering the available information, EPA has determined that the technical basis (i.e., the best system of emission reduction which the Administrator determines has been adequately demonstrated, or 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 SCR 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 the cost of controls 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 and no units have been able to achieve this level of control for an extended period of time. EPA disagrees with the commenters’ assessment, however, 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. Although we do believe that these technologies have been currently demonstrated to be capable of achieving significant reductions in Hg emissions, we do not believe that they 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 for an extended period of time 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, 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 “Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update” (OAR-2002-0056), since the release of the earlier White Paper “Control of Mercury Emissions from Coal-fired Electric Utility Boilers” (OAR-2002-0056), 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 have been demonstrated to effectively remove Hg and 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. Considering the progress made with halogenated activated carbon sorbents and other chemical injection approaches to date, we now believe that optimized multipollutant controls may be available in the 2010 to 2015 timeframe for commercial application on most, if not all, key combinations of coal rank and control technology to provide Hg removal levels between 90 and 95 percent. Such optimized controls could include use of sorbent (ACI or halogenated ACI) with enhanced SCR and/or enhanced FGD systems. These controls provide justification for a 2018 cap at a level below what is projected to be achieved from SO_2 and NO_x reduction levels alone. Although EPA is optimistic that such controls may be available for use on some scale prior to 2018, it does not believe that such controls can be installed and operated on a national scale before that date.

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) at the present time. 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 at this time, 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 in the two-phase cap-and-trade program finalized today will serve to advance the technologies such that they are widely available for use in complying 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 non-air 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 which ignores costs at what is referred to the floor level of control. 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 agrees with the commenters who indicated that the new-source NSPS limits were not established in a manner consistent with the requirements of CAA section 111. 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: 0.0026 ng/J (21 x 10^{-6} lb/MWh);
Subbituminous units:
  - wet FGD units 0.0055 ng/J (42 x 10^{-6} lb/MWh);
  - dry FGD units: 0.0103 ng/J (78 x 10^{-6} lb/MWh);
Lignite units: 0.0183 ng/J (145 x 10^{-6} lb/MWh);
Coal refuse units: 0.00017 ng/J (1.4 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 (OAR-2002-0056).

To establish the revised new-source limits, EPA reexamined 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. 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 adequately demonstrated system of emission reduction, also referred to as a best demonstrated control technology (BDT), for each subcategory. To do this, we determined the combination of control technologies that a new unit would install under the current NSPS to comply with the emissions standards for PM, SO_2, and NO_x. Based on the available data, units using these combinations of controls had the highest reported control efficiency for Hg emissions. Thus, we determined that BDT for each subcategory of units is a combination of controls that would generally be installed to control PM and SO_2 under the NSPS. For bituminous units, BDT was determined to be the combination of a fabric filter and a FGD (wet or dry) system. However, recent test data reports show that a bituminous coal based system including a SCR, ESP and wet FGD may also be capable of meeting the performance limit set for bituminous coal–fired Utility Units, and this information was considered in setting the new source limits. For subbituminous units, BDT was determined to be dependent on water availability. For subbituminous units located in the western U.S. that may face potential water restriction and, thus, do not have the option of using a wet FGD system for SO_2 control, BDT is a combination of either a fabric filter with a spray dryer absorber (SDA) system or an ESP with a SDA system. For subbituminous units that do not face such potential water restrictions, BDT is a fabric filter in combination with a wet FGD system. For lignite units, BDT is either a fabric filter and SDA system or an ESP with a wet FGD system.

To determine the appropriate achievable Hg emission level for each coal type, a statistical analysis was conducted. Specifically, the Hg emissions limitation achievable for each coal type was determined based on the highest reported annual average Hg fuel content for the coal rank being controlled by the statistically-calculated control efficiency for the BDT determined for that fuel type. The control efficiency for BDT was calculated by determining the 90th percentile confidence level using the one-sided z-statistics test (i.e., the Hg removal efficiency, using BDT, estimated to be achieved 90 percent of the time). 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 annual fuel Hg content reported for any unit in the coal rank. Because 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 highest annual average inlet Hg was adjusted to determine the potential maximum Hg emissions that would be emitted if BDT was employed. The calculated 90th percentile confidence limit control reduction for each subcategory, based on the calculated highest annual average uncontrolled Hg emissions, in lb Hg/TBtu, for the subcategory 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 20 x 10^{-6} lb/MWh to 39 x 10^{-6} lb/MWh; those for subbituminous-fired units range from 11 x 10^{-6} lb/MWh to 126 x 10^{-6} 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 the annual average fuel Hg content in the ICR data 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. Further, it is not our intention to exclude any type of domestic coal from the market. If information becomes available in the future that we feel adversely impacts the coals or the fuel market, we will review and reconsider these limits.

As required by CAA section 111(a)(1), EPA has considered the cost of achieving the reductions in Hg emissions required by the new-source standards, the non-air quality health and environmental impacts arising from the implementation of the new-source standards and the energy requirements associated with the new-source standards and determined that they are all reasonable. (The costs of complying with CAMR as a whole are discussed briefly in section V.C., below, and in more detail in the two air dockets for the CAMR rule [electronic docket - Docket ID No. OAR-2002-0056; legacy docket - Docket ID No. A-92-55]. The non-air quality health and environmental impacts arising from the implementation of CAMR, as well as the energy requirements associated with CAMR, are discussed briefly in section V.B., below, and in more detail in Docket ID No. OAR-2002-0056 and Docket ID No. A-92-55.)

D. 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 and 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 the final rule, EPA interprets 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 to include a cap-and-trade program. Section 111(d)(1)(B) refers to the “implementation and enforcement of such

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[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.

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(l) 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(l) 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]

We note that EPA has on one prior occasion authorized emissions trading under section 111(d). (The Emission

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[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, <u>reprinted in</u> 4 Congressional research Service, A Legislative History of the Clean Air Act Amendments of 1977, 2559.

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 based on control technology available in the relevant time frame is the best system for reducing Hg emissions from existing 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 SO_2 emissions from utilities.

Title IV requires sources to hold allowances for each ton of SO_2 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 SO_2 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

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[4] Non-electricity generating units are also included in the States’ programs.

programs are contained in SIP 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 SO_2 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.

2. 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, SO_2, 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, SO_2, and Hg. Our analyses show that the use of FGD (to reduce SO_2 emissions) and SCR (to reduce NO_x) also has the effect of controlling 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 SO_2 and NO_x reductions will also achieve significant reductions in oxidized Hg. As explained elsewhere in this document, reductions in this Hg species are 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 SO_2 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. Current information on these technologies, as outlined in the revised ORD White Paper, “Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update,” (OAR-2002-0056) is only adequate for us to conclude that such technologies are adequately demonstrated for use in the 2010 to 2018 time-frame to allow for compliance with the CAMR Phase II Hg cap. Therefore, for purposes of setting the 2010 Hg cap, we conclude that Hg reductions achieved as a “co-benefit” of controlling SO_2 and NO_x under CAIR should dictate the appropriate cap level. We find that requiring SO_2 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 SO_2 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 fixed cap in the final rule.

In the final CAIR, EPA evaluated the amounts of SO_2 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 SO_2 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 SO_2 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 SO_2 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. Utility Mercury Emission Reductions Expected as Co-Benefits From CAIR

The final CAIR requires annual SO_2 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 SO_2 and NO_x reduction requirements and the ozone season NO_x requirements. CAIR was designed to achieve significant emissions reductions of SO_2 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 SO_2 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 SO_2 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 SO_2 emissions and the majority of stationary NO_x emissions, and represents highly cost-effective sources of reductions of SO_2 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 SO_2 would come through the installation of scrubbers, for SO_2 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 SO_2 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 the 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 SO_2 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 SO_2 emission allowances. Companies have an incentive to achieve greater and faster SO_2 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. With respect to oxidized Hg, emissions in 2020 are 7.9 tons compared to 20.6 tons in 2001. This 62 percent drop in oxidized Hg emissions is particularly important because this species of Hg deposits more readily. For further discussion of EPA modeling results and projected emissions see Chapter 8 of the Regulatory Impact Assessment (RIA).

iii. 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 SO_2 and NO_x under CAIR. We conclude that this approach is warranted because we find Hg-specific air pollution control technologies such as ACI is adequately demonstrated for use 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.

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. See 69 FR 4652, 4700-4703 for a detailed discussion of the benefits of the cap-and-trade approach.

As discussed above, under the CAIR scenario modeled by EPA, SO_2 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 SO_2 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 SO_2 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.

As discussed in detail in the separate <u>Federal Register</u>

notice announcing EPA’s revision of its December 2000 regulatory determination and removing coal- and oil-fired Utility Units from the CAA section 112(c) list, EPA believes that the term “standard of performance” as used in CAA section 111 can include market-based programs such a cap-and-trade program. The EPA also believes that in the context of a cap-and-trade program, the phrase “best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impacts and energy requirements) the Administrator determines has been adequately demonstrated” refers to the combination of the cap-and-trade mechanism and the technology needed to achieve the chosen cap level. The EPA further believes that a particular technology can be adequately demonstrated to achieve a specified level of emissions reduction at one point in time, but, for a number of possible reasons, not be capable of achieving that level of reductions on a broad scale until a later point in time. For example, EPA might conclude that a particular technology is capable of achieving reductions in the emission of specified pollutants in the range of 90 to 95 percent, while at the same time concluding that the technology is not currently commercially available and, therefore, not susceptible to widespread use. As a result, it would be inappropriate for EPA to establish a cap based on the use of such controls and require compliance with that cap in the near term, but reasonable to establish a cap on that basis and require compliance with that cap at a later point in time when the necessary technology becomes widely available.

Section 111 authorizes EPA to promulgate standards of performance based on systems of emission reduction that have been “adequately demonstrated.” Traditionally EPA has set its section 111 standards based on a determination that particular control technologies are “adequately demonstrated.” In today’s final rule, EPA has determined that the technologies necessary to achieve the emission cap limits for 2010 have been adequately demonstrated, and that the technologies necessary to achieve the 2018 caps have been adequately demonstrated to be available to achieve compliance with those limits by 2018.[5]

In Portland Cement Association v EPA (486 F.2d 375) (D.C. Cir. 1973), the Court rejected the argument that the words “adequately demonstrated” in section 111 meant that the relevant technology already must be in existence and that plants now in existence be able to presently meet the proposed standards. Rather, the Act’s requirement that the

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[5] Even assuming, arguendo, that the term “standard of performance” prohibited an emissions cap and allowance trading program, the regulatory approach being employed in today’s rule and the technologies on which EPA has based its cap calculations are consistent with and permitted by section 111.

degree of emission limitation be “adequately demonstrated” means that a plant now in existence must be able to meet the presently-effective standards for existing units, but that insofar as new plants and future requirements are concerned, section 111 authorizes EPA to “look toward what may fairly be projected for the regulated future, rather than the state of the art at present.” The court said:

> The Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on “crystal ball” inquiry. 478 F.2d at 629. As there, the question of availability is partially dependent on “lead time,” the time in which the technology will have to be available. Since the standards here put into effect will control new plants immediately, as opposed to one or two years in the future, the latitude of projection is correspondingly narrowed. If actual tests are not relied on, but instead a prediction is made, “its validity as applied to this case rests on the reliability of [the] prediction and the nature of [the] assumptions.” (citation omitted)

See also Lignite Energy Council v. EPA, 198 F.3d 930 (D.C. Cir. 1999) (section 111 “looks toward what may fairly be projected for the regulated future, rather than the state of the art at present”) (quoting Portland Cement). These cases address section 111(b) standards for new sources, where achievement of the standards is mandated on a short-term basis. We believe that EPA standards set under the authority of section 111(d), where the compliance deadlines are not so immediate, afford EPA significant flexibility, commensurate with the amount of lead-time being given to affected sources. The cases make clear that while a determination about a technology or performance standard's achievability may not be based on "mere speculation or conjecture," a technology or standard that may not necessarily be considered "adequately demonstrated" at present nonetheless can be considered "adequately demonstrated" for a compliance date in the future. We have explained in today's action why we believe both the 2010 and 2018 emissions caps can be met. Since we believe that Hg-specific technologies capable of meeting the requirements of the 2018 emission limits will be available for broad commercial deployment by 2018, we believe those technologies are "adequately demonstrated" for the 2018 emission caps.

Here, EPA has concluded that Hg-specific controls, such as ACI, have been adequately demonstrated as being effective in substantially reducing Hg emissions, but are not currently available for commercial application on a broad scale. As a result, EPA cannot establish a Hg emission cap based on the widespread use of Hg-specific controls and require compliance with that cap in the near term. The EPA has, therefore, set the level of the 2010 cap on Hg emissions on the basis of the reductions in Hg emissions achievable as co-benefits of efforts to reduce emissions of SO_2 and NO_x in accordance with CAIR. The EPA believes that establishing the phase-one cap on the basis of these co-benefits fulfills its obligation to set a standard of performance which is both based on the best system of emissions reduction that has been adequately demonstrated and achievable in the designated time frame.

As stated above, EPA has determined that Hg-specific controls have been adequately demonstrated as being effective in substantially reducing Hg emissions, but that such controls are not currently available for commercial application on a broad scale and, therefore, cannot serve as the basis for the 2010 Hg emissions cap. EPA believes, however, based on currently available information (ORD revised white paper "Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update," and DOE white paper "Mercury Control Technologies," both of which may be found in the OAR-2002-0056), that such controls will be commercially available sometime after 2010 and can be installed and operational on a nation-wide basis by 2018. The EPA has, therefore, established a Phase II Hg emissions cap based on the reductions in Hg emissions founded in the CAIR program and reductions that can be reasonably obtained through the use of Hg-specific controls. This cap is effective in 2018. That is, the 2018 cap is based on the level of Hg emissions reductions that will be achievable by the combined use of co-benefit (CAIR) and Hg-specific controls. The Phase II cap is timed such that these technologies can be installed and operational on a nationwide basis, i.e., until the technology becomes generally available.

The need to achieve Hg reductions beyond those secured through the CAIR co-benefits program are wholly consistent with the Agency’s mission to leverage the monies spent domestically on global reductions of anthropogenic Hg emissions. As explained elsewhere in this preamble and the supporting docket, in order to significantly impact nationwide Hg deposition and, thus, human exposure to MeHg, the U.S. must be a leader in incentivizing global Hg emissions reductions. To that end, the Phase II cap serves as a driver for continued research and development of Hg-specific control technologies, while providing a global market for the application of such equipment, which ultimately may serve to significantly reduce the global pool of Hg emissions. The timing of the Phase II cap is such that new technologies can be developed, installed, demonstrated and commercially deployed with little impact to the stability of the power grid.

EPA is today finalizing a new source performance standard for Hg for coal-fired electric utility steam generating units under section 111 of the CAA in lieu of a MACT standard for Hg. As set forth in greater detail below and in the related rulemaking, the Agency has determined that it is not “necessary and appropriate” to establish a MACT standard under section 112 for electric utility steam generating units since utility HAP emissions remaining after implementation of other requirements of the CAA do not pose hazards to public health. For this reason, it is not necessary for the Agency to undertake any further analysis of Hg emissions from existing units in order to establish a MACT floor, as this information is irrelevant to the development of the NSPS. Nor is it necessary to conduct an additional cost-benefit analysis of potential MACT standards since the Agency has concluded, as a matter of law and policy, that a MACT standard is not appropriate or necessary.

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 the final rule.

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. These cost considerations include establishing a cap level that does not have significant impacts on energy supply and the cost of energy to the consumer. 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.

3. State and Indian Country Emissions Reductions Requirements.

The EPA below also outlines a method for apportioning the nation-wide budget to individual States and to coal-fired Utility Units located in Indian country. 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 in Indian country. (As used herein, the term “Indian country” generally refers to all areas within Indian reservations, dependent Indian communities, and Indian allotments. The EPA or, in appropriate circumstances, an individual Tribe generally will be responsible for implementing a trading program in Indian country.) As discussed further below, each State 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 coal-fired Utility Units. States are not required to adopt and implement the proposed emission trading rule, but they are required to be in compliance with their statewide Hg emission budget. 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. Mercury emission budgets have also been assigned to coal-fired Utility Units that will be affected by this rule which are located in Indian country. The EPA generally will implement the emission trading rule for coal-fired Utility Units located in Indian country unless a Tribe seeks and obtains Treatment-as-a-State (TAS) status and submits a Tribal implementation plan (TIP) to implement the allocated Hg emissions budget. Eligible Tribes which choose to do so will be responsible for submitting a 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 Indian country emission budgets.

Each of the States and the District of Columbia covered by today’s final rule has been assigned a State emissions budget for Hg. A Hg emissions budget has also been assigned to each coal-fired Utility Unit located in Indian country.

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. Tribes which choose to seek and obtain TAS status for that purpose, have the same flexibility in developing an appropriate TIP. The State Hg emission budgets are a permanent cap regardless of growth in the electric sector and, therefore, States have the responsibility of incorporating new units in their Hg emission budgets. Similarly, the Hg emission budgets allocated to coal-fired Utility Units located in Indian country act as a permanent cap and EPA or a Tribe which has obtained TAS status and is implementing an approved TIP has responsibility for incorporating new units into the allocated Hg emission budget.

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 coal-fired Utility Unit located in Indian country 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 Indian country, 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 the allocation methodology in the model cap-and-trade program a mechanism 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 Indian country 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 SO_2 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 the final rule, 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 (see “Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State, and Indian Country Emissions Budgets,” EPA, March 2005).

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 SO_2 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 Indian country 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 Indian country emission budgets with the State budgets equaling the total of the individual unit emission limits in a given State (see Table 1 below). Similarly, sufficient allowances have been allocated to coal-fired Utility Units located in Indian country to cover the individual unit emission limits for those units. States also have the flexibility to not participate in the trading program or require more stringent Hg emissions reductions. States that do not participate in the trading program can establish their own methodology for meeting State Hg budgets by obtaining 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 budgets remain the same after the inclusion of new units and States have the responsibility of addressing new units in their respective emission budgets. Similarly, the budgets for coal-fired Utility Units located in Indian country will remain the same after the inclusion of new units and EPA or a Tribe with an approved TIP, as appropriate, has responsibility for addressing new units in the respective emission budget.

EPA received comments from Tribes noting that only States currently receive allowances under the proposal, despite unit allocations being made to sources located in Indian country, and requesting that Tribes be accommodated into the cap-and-trade program. Because under CAA authority eligible Tribes may be treated in the same manner as States for CAA programs for reservations and for other areas within their jurisdiction, EPA agrees with the commenters that these Tribal sources need to be included in the cap-and-trade program and the final CAMR establishes budgets for existing coal-fired sources located in Indian country.

In the final rule, EPA is establishing a Tribal budget for three existing coal-fired Utility Units in Indian country. 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 a budget for these Utility Units. The budget for units located in Indian country was calculated using the same methodology as State budgets. In the proposed rule, these three units in Indian country were erroneously 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 these sources to the Indian country emission budget.

For areas of Indian country that do not currently have any coal-fired electricity generation, EPA intends to address any future planned construction of coal-fired Utility Units in those areas on a case-by-case basis, by working with the relevant Tribal government to regulate the Utility Units through either a TIP, if an eligible Tribe chooses to submit one, 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 allocation provisions for new generation which locates in Indian country 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 Indian country 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 Indian Country	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	2.057	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 Reservation Indian Country	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

As required by CAA section 111(a)(1), EPA has considered the cost of achieving the reductions in Hg emissions mandated by the section 111(d) requirements for existing Utility Units, the non-air quality health and environmental impacts arising from the implementation of those requirements and the energy requirements associated with those requirements and determined that they are all reasonable. (The costs of complying with CAMR as a whole are discussed briefly in section V.C., below, and in more detail in the two air dockets for the CAMR rule [electronic docket - Docket ID No. OAR-2002-0056; legacy docket - Docket ID No. A-92-55]. The non-air quality health and environmental impacts arising from the implementation of CAMR, as well as the energy requirements associated with CAMR, are discussed briefly in section V.B., below, and in more detail in Docket ID No. OAR-2002-0056 and Docket ID No. A-92-55.)

E. 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 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. The final rule adopts the basic structure of this model 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 SO_2 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 SO_2 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 (40 CFR 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 NCR, 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 NCR 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 about 1 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 SO_2 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 NCR 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 in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWH, which ever is greater, 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 NCR, 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.

The final rule finalizes the proposal to require States to submit unit-by-unit allocations of allowances for existing units for a given year no less than three years prior to 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 the final rule, 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 the final rule, 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 NCR 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, 2001 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, 2001 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 2000 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 7,900 Btu per kilowatt-hour (Btu/kWh). The 7,900 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 EIA’s Annual Energy Outlook (AEO) 2004. See Energy Information Administration, “Annual Energy Outlook 2004, with Projections to 2025,” January 2004. Assumptions for the NEMS model can be found at http://www.eia.doe.gov/oiaf/archive/aeo04/assumption/tbl38.html). 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 Indian country-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.[6] 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.[7] Each subsequent year, an additional 1 percent of the allowances (for the first 20 years of the program), and then an additional 2.5

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[6] Auctions could provide States with a less distortionary source of revenue.

[7] 5 percent of the allowances will go to a new source set aside.

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 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, the final rule 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 NCR 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.

<u>Comments Regarding Unrestricted Banking After the Start of</u>

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 commmenters 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.

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 ounce) 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/ounce 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 SO_2 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 the 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 ounce of emissions and that one ounce of reported emissions from one source is equivalent to one ounce 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 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 ounce) 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 to reflect changes in the monitoring requirements 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;

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.

F. Standard of Performance Requirements

1. Introduction

As proposed in the NCR 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 NCR 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 NCR 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, the final rule 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.

G. 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 ounce (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.

Today’s final rule adopts under 40 CFR 75.81(a) 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 SO_2 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 ounce/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 ounce/yr) or less, annual emission testing is required. For units with Hg emissions greater than 144 ounce/yr but less than or equal to 464 ounce/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 (:g/scm), whichever is greater. If, at the end of a particular calendar year, the reported annual Hg mass emissions for a unit exceed 464 ounce, 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 SO_2 and NO_x (see 63 FR 57484, October 27, 1998). These provisions require the use of conservatively high default emission rates to quantify SO_2 and NO_x emissions. EPA determined the appropriate SO_2 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 SO_2 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 units = $15,939,000/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 units = $20,803,500/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 SO_2 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 SO_2 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 SO_2 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 QA SO_2 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 :g/scm) an alternate specification of 1.0 :g/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 :g/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 :g/scm, the results would be acceptable if the mean difference between the reference method does not exceed 1.0 :g/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 :g/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 $HgCl_2$ 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 SO_2 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 “$HgCl_2$ 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 SO_2, NO_x, CO_2, 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 $HgCl_2$ 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 $HgCl_2$ 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 QA 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 ± 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 40 CFR part 75, 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 40 CFR part 75, 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, 40 CFR part 75, 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 40 CFR part 75, appendix K. Many provisions of proposed Method 324 have been included in 40 CFR part 75, 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 40 CFR part 75, appendix K, are as follows:

- 40 CFR part 75, 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);

- 40 CFR part 75, 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;
- 40 CFR part 75, appendix K, specifies the frequency of dry gas meter calibration and the appropriate calibration procedures;
- 40 CFR part 75, 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 trains 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 O_2 or CO_2 diluent gas monitor, and an automated data acquisition and handling system) to measure Hg emission rate in lb/10^{12} Btu were allowed in the proposed rule.

One cementer 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 SO_2.

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 SO_2 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 SO_2, i.e., as the product of the Hg concentration and the stack gas flow rate.

V. Summary of the Environmental, Energy, Cost, and Economic Impacts

A. What are the air quality impacts?

EPA has assessed the change in the amount of Hg deposited in the continental US as a result of this rulemaking. The recently promulgated Clean Air Interstate Rule (CAIR) significantly reduced utility attributable Hg deposition. Both the selected CAMR approach and the regulatory alternative result in small additional shifts in the overall distribution of Hg deposition from utilities reactive to the CAIR result. The following table presents the frequency and cumulative distributions of the reductions in deposition associated with the CAMR requirements and the CAMR alternative. We also provide the reduction in deposition from the 2020 base case with CAIR implemented relative to the 2001 base case. This change (2001 Base - 2020 CAIR) shows that there are both increases and decreases in deposition. Negative reductions (increases) are due to growth in non-utility Hg emissions, and growth in utility emissions in areas unaffected by CAIR. Reductions in deposition are largely due to the implementation of CAIR controls at utilities.

Table V.1. Distributions of Reductions in Total Mercury

Deposition

	2001 Base - 2020 Base (with CAIR)		2020 Base (with CAIR) - 2020 CAMR Requirements		2020 Base (with CAIR) - 2020 CAMR Alternative		2020 CAMR Requirements - 2020 CAMR Alternative	
Range (:g/m^2)	Percent	Cumulative %	Percent	Cumulative %	Percent	Cumulative %	Percent	Cumulative %
<=0	6.59%	6.59%	2.13%	2.13%	0.83%	0.83%	0.28%	0.28%
0 - 1	58.02%	64.61%	97.03%	99.17%	97.87%	98.70%	99.58%	99.86%
1 - 2	12.06%	76.67%	0.83%	100.00%	1.30%	100.00%	0.14%	100.00%
2 - 3	7.33%	84.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%
3 - 4	5.10%	89.10%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%
4 - 5	3.71%	92.81%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%
5 - 10	6.08%	98.89%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%
10 - 15	0.88%	99.77%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%
15 - 20	0.23%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%

Source: Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls

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

According to E.O. 13211 “Actions that Significantly Affect Energy Supply, Distribution, or Use,” this rule is not significant, measured incrementally to CAIR, 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.

Several aspects of CAMR are designed to minimize the impact on energy production. First, EPA recommends a trading program rather than the use of command-and-control regulations. Second, compliance deadlines are set cognizant of the impact that those deadlines have on electricity production. Both of these aspects of CAMR reduce the impact of the proposal on the electricity sector.

C. What are the cost and economic impacts?

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 SO_2 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.

Additional information on the cost and economic impacts of CAMR is provided in the discussion under EO 12866 below.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under EO 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 EO. 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 EO.

In view of its important policy implications and potential effect on the economy of over $100 million, the final rule has been judged to be an economically "significant regulatory action" within the meaning of the EO. As a result, the final rule 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) (OAR-2002-0056).

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?

a. Control Scenario

The final CAMR requires annual Hg reductions for the power sector in 50 states, the District of Columbia, and in Indian country. EPA considered the final CAIR for SO_2 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 and EPA’s analysis assumes that States will adopt this more cost effective approach.

b. Cost Analysis and Economic Impacts

For the final rule, 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, SO_2, 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 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 SO_2 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 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: shark, swordfish, king mackerel, tilefish 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).

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)[8]. Some subpopulations in the U.S. (e.g., certain 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.

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

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[8] National Research Council (NRC). 2000. Toxicological Effects of Methylmercury. Committee on the Toxicological Effects of Methylmercury, Board on Environmental Studies and Toxicology, Commission on Life Sciences, National Research Council. National Academy Press, Washington, DC.

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.[9] 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.

CAMR may also reduce emissions of directly emitted PM,

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[9] See footnote 3 of Chapter 11 of the Regulatory Impact Analysis for an explanation of the basis for the monetization.

which contribute to the formation of fine particles ($PM_{2.5}$). 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. 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 potentially 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. As explained in the RIA, we believe that the focus of the analysis on recreationally and subsistence caught freshwater fish captures the bulk of the benefits. Nevertheless, we believe that the analysis captures the bulk of the benefits.

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.

This approach forms the core analytic underpinnings for the final benefit numbers, but incorporates an assumption of no threshold, and, therefore, reflects an upper-bound on the number of people affected by Hg. A more simplified approach used to simulate exposure scenarios under the assumption of two different thresholds. This threshold analysis provides “scaling factors,” or benefits as a percent of the no threshold case. We consider two benchmark levels of exposure established by regulatory agencies as possible thresholds: (1) a threshold equal to EPA’s RfD of 0.1 ug/kg-day and (2) a threshold in the neighborhood of the World Health Organization and Health Canada benchmarks of .23 and .2 ug/kg-day respectively. Scaling factor for the no threshold benefits from the more detailed analysis range from 4 percent to 34 percent. The final estimates of IQ-related benefits are arrayed in a hierarchy from most certain to less certain benefits.

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, with an average time span of one to three decades (10 to 30 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. The 10- and 20-year lag periods are presented as the likely outcome of results from the analysis, while the 5- and 50-year lag periods are presented to show the outcomes if the time span to steady-state is less than or more than the average lag periods observed in the case studies.

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 (in 2020, two years after imposition of the phase II cap) 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 range of annual benefits of CAMR under a 10- to 20-year lag period are approximately $0.4 million to $3.0 million using a 3 percent discount rate (or $0.2 million to $2.0 million using a 7 percent discount rate).

In addition to the benefits of reducing exposures to MeHg from recreational freshwater angling, there are several additional benefits that may be associated with reduced exposures to MeHg; however, the literature with regard to these effects is less developed than the literature for childhood neurodevelopmental effects[10]. Because of the uncertainty associated with these effects, and, in most cases, the lack of sufficient data to evaluate whether or not these effects are present at levels associated with U.S. exposures, we did not quantify these benefits. Most notably these effects include:

- Cardiovascular effects - Some recent epidemiological studies in men suggest that MeHg is associated with a higher risk of acute myocardial infarction, coronary heart disease and cardiovascular disease in some populations. Other recent studies have not observed this association. The studies that have observed an association suggest that the exposure to MeHg may attenuate the beneficial effects of fish consumption. The findings to date and the plausible biologic mechanisms warrant additional research in this arena (Stern 2005; Chan and Egeland 2004).
- Ecosystem effects - Plant and aquatic life, as well as fish, birds, and mammalian wildlife can be affected by Hg exposure; however overarching conclusions about ecosystem health and population effects are difficult to make at this

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[10] It should be noted that the degree of uncertainty associated with these effects varies as does our knowledge about whether the effects are seen at levels consistent with those in the U.S.

time.

- Other effects - There is some recent evidence that exposures of MeHg may result in genotoxic or immunotoxic effects. Other research with less corroboration suggest that reproductive, renal, and hematological impacts may be of concern. Overall, there is a relatively small body of evidence from human studies that suggests exposure to MeHg can result in immunotoxic effects and the NRC concluded that evidence that human exposure caused genetic damage is inconclusive. There are insufficient human data to evaluate whether these effects are consistent with levels in the U.S. population. See Chapter 2 of the RIA.

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 an illustrative 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 are approximately $1.4 million to $40 million; however, the calculation of these benefits is highly dependent on uncertain future technology choices of the industry. Because of this significant uncertainty, therefore, these benefit estimates are not included in our primary benefit estimate.

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 (shark, swordfish, king mackerel, tilefish) 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.

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

The costs presented above are EPA’s best estimate of the direct private costs of the CAMR. In estimating the net benefits of regulation (benefits minus costs), the appropriate cost measure is “social costs.” Social costs represent the total welfare costs of the rule to society. These costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth. Using these alternate discount rates, the social costs of this rule are estimated to be approximately $848 million in 2020 when assuming a 3 percent discount rate. These costs become $896 million in 2020 if one assumes a 7 percent discount rate. The costs of the CAMR using the adjusted discount rates differ from the private costs of the CAMR generated using IPM because the social costs do not include certain transfer payments, primarily taxes, that are considered a redistribution of wealth rather than a social cost.

As is discussed above, the total social benefits that EPA was able to monetize in the RIA total $0.4 million to $3.0 million using a 3 percent discount rate, and $0.2 million to $2.0 million using a 7 percent discount rate.

Thus, the annual net benefit in 2020 (social benefits minus social costs) of the CAMR program is approximately -$846 million or -$895 million (using 3 percent and 7 percent discount rates, respectively) annually in 2020. Although the rule is expected to result in a net cost to society, it achieves a significant reduction in Hg emissions by domestic sources. In addition, the cost of reduced earnings borne by U.S. citizens from Hg exposure falls disproportionately on prenatally exposed children of populations who consume larger amounts of recreationally caught freshwater fish than the general population.

The annualized cost of the CAMR, as quantified here, is EPA’s best assessment of the cost of implementing the CAMR, assuming that States adopt the model cap-and-trade program. These costs are generated from rigorous economic modeling of changes in the power sector due to the CAMR. This type of analysis using IPM has undergone peer review and been upheld in Federal courts. The direct cost includes, but is not limited to, capital investments in pollution controls, operating expenses of the pollution controls, investments in new generating sources, and additional fuel expenditures. The EPA believes that these costs reflect, as closely as possible, the additional costs of the CAMR to industry. The relatively small cost associated with monitoring emissions, reporting, and recordkeeping for affected sources is not included in these annualized cost estimates, but EPA has done a separate analysis and estimated the cost to less than $76 million (see section X.B., Paperwork Reduction Act). However, there may exist certain costs that EPA has not quantified in these estimates. These costs may include costs of transitioning to the CAMR, such as employment shifts as workers are retrained at the same company or re-employed elsewhere in the economy, and certain relatively small permitting costs associated with title IV that new program entrants face. Costs may be understated since an optimization model was employed that assumes cost minimization, and the regulated community may not react in the same manner to comply with the rules. Although EPA has not quantified these costs, the Agency believes that they are small compared to the quantified costs of the program on the power sector. The annualized cost estimates presented are the best and most accurate based upon available information.

Table 3. Summary of Annual Benefits, Costs, and Net Benefits of the CAMR[a] (billions of 1999 dollars)

Description	2020 (millions of 1999 dollars)
Social Costs[c]	
3 percent discount rate	$848.0
7 percent discount rate	$896.0
Social Benefits [b,c]	
3 percent discount rate	
EPA RfD	$0.4 - $1.0
No Threshold	$1.7 - $3.0
7 percent Discount rate	
EPA RfD	$0.2 - $0.7
No Threshold	$0.8 - $2.0
Unquantified benefits and costs	U
Annual Net Benefits (Benefits-Costs)[c,d]	
3 percent discount rate	
EPA RfD	-$848 + U
No Threshold	-$846 + U
7 percent discount rate	
EPA RfD	-$896 + U
No Threshold	-$895 + U

[a] All estimates are rounded to first significant digits and represent annualized benefits and costs anticipated in 2020.

[b] Not all possible benefits are quantified and monetized in this analysis. B is the sum of all unquantified

benefits. Potential benefit categories that have not been quantified and monetized are listed in Table 2.

[c] Results reflect 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (U.S. EPA, 2000, and OMB, 2003).[11]

[d] Net benefits are rounded to the nearest $100 million. Columnar totals may not sum due to rounding.

Every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Gaps in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects. Gaps in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes that can be quantified. Although uncertainties in the underlying scientific and economics

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[11] United States Environmental Protection Agency, 2000. Guidelines for Preparing Economic Analyses. www.yosemite1.epa.gov/ee/epa/eed/hsf/pages/Guideline.html. Office of Management and Budget, The Executive Office of the President, 2003. Circular A-4. www.http://www.whitehouse.gov/omb/circulars.

literature (that may result in overestimation or underestimation of benefits) are discussed in detail in the economic analyses and its supporting documents and references, the key uncertainties which have a bearing on the results of the benefit-cost analysis of this rule include the following:

- EPA’s inability to quantify potentially significant benefit categories;
- Uncertainties in population growth and baseline incidence rates;
- Uncertainties in projection of emissions inventories and air quality into the future;
- Uncertainty in the estimated relationships of health and welfare effects to changes in pollutant concentrations;
- Uncertainties in exposure estimation; and
- Uncertainties associated with the effect of potential future actions to limit emissions.

Despite these uncertainties, we believe the benefit-cost analysis provides a reasonable indication of the expected economic benefits of the rulemaking in future years under a set of reasonable assumptions.

The benefits estimates generated for this rule are subject to a number of assumptions and uncertainties, that are discussed throughout the “Regulatory Impact Analysis for the Final Clean Air Mercury Rule” (March 2005) (OAR-2002-

0056).

B. Paperwork Reduction Act

The information collection requirements in this rule will be submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The information collection requirements are not enforceable until OMB approves them.

The information requirements are based on notification, recordkeeping and reporting requirements in the NSPS. The recordkeeping and reporting requirements are specifically authorized by section 114 of the Act (42 U.S.C. 7414) and are, therefore, mandatory. All information submitted to EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR.

The EPA is still working on the projected cost and hour burden for information requirements mandated by the new-source NSPS. Those estimates will be provided to OMB and notice of their availability provided to the public when they are completed. The information requirements mandated by the NSPS requirements for existing sources will be essentially the same as those for the Clean Air Interstate Rule (CAIR). The ICR for CAIR has been designated as EPA ICR number 2137.01. The EPA will, nevertheless, provide a full estimate of the projected cost and hour burden for those information requirements to OMB and provide the public with notice of the availability of that information. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA’s regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the Federal Register to display the OMB control number for the approved information collection requirements contained in this final rule.

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 NCR 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 that 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, other than those that are new sources subject to new source performance standards (NSPS). We believe that there will not by any such small entities subject to this rule because the IPM projects no new construction of coal-fired utility units. Additionally, the

CAMR rule does not establish requirements applicable to small entities because this rule requires 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 the 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’s 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 final rule consistent with the requirements of UMRA section 202. Furthermore, as EPA 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. Furthermore, in a manner consistent with the intergovernmental consultation provisions of UMRA section 204, EPA carried out consultations with the governmental entities affected by this rule.

For today’s rule, 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.

EPA has determined that this rule may result in expenditures of more than $100 million to the private sector in any single year. EPA believes that the final rule represents the least costly, most cost-effective approach to achieve the air quality goals of this rule. The costs and benefits associated with the final rule are discussed above and in the RIA.

As noted earlier, however, EPA prepared for the final rule the statement that would be required by UMRA if its statutory provisions applied, and EPA has consulted with governmental entities as would be required by UMRA. Consequently, it is not necessary for EPA to reach a conclusion as to the applicability of the UMRA requirements.

E. Executive Order 13132: Federalism

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

This rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132. The CAA establishes the relationship between the Federal government and the States, and this rule does not impact that relationship. Thus, EO 13132 does not apply to this rule. In the spirit of EO 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comment on this rule from State and local officials.

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

EO 13175, entitled “Consultation and Coordination with Indian Tribal Governments” (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure “meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications.” This final rule does not have “Tribal implications” as specified in EO 13175 because it does not have a substantial direct effect on one or more Indian Tribes. No Tribe has implemented a Federally enforceable air quality management program under the CAA at this time. Furthermore, this rule does not affect the relationship or distribution of power and responsibilities between the Federal government and Indian Tribes. The CAA and the TAR establish the relationship of the Federal government and Tribes in developing plans to attain the national ambient air quality standards (NAAQS), and this rule does nothing to modify that relationship. Because this rule does not have Tribal implications, EO 13175 does not apply.

This rule addresses pollution composed of Hg and mercuric compounds. The final CAMR requires annual Hg reductions for the power sector in 50 States, the District of Columbia, and in Indian country, through a cap-and-trade system that States and eligible Tribes have the option of adopting. The CAA provides for States and eligible Tribes to develop plans to regulate emissions of air pollutants within their areas. The regulations clarify the statutory obligations of States and eligible Tribes that develop plans to implement this rule. The Tribal Authority Rule (TAR) (40 CFR 49.1 - 49.11) gives eligible Tribes the opportunity to develop and implement CAA programs, but it leaves to the discretion of the Tribe whether to develop these programs and which programs, or appropriate elements of a program, the Tribe will adopt. As noted earlier, the EPA will implement the emission trading rule for coal-fired Utility Units located in Indian Country in accordance with the TAR unless the relevant Tribe for the land on which a particular coal-fired Utility Unit is located seeks and obtains TAS status and submits a TIP to implement the allocated Hg emissions budget. Tribes which choose to do so will be responsible for submitting a 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.

EPA notes that in the event a Tribe does implement a TIP in the future, today’s rule could have implications for that Tribe, but it would not impose substantial direct costs upon the Tribe, nor preempt Tribal law. As provided above, EPA has estimated that the total annual private costs for the rule for Hg as implemented by State, local, and eligible Tribal governments (or EPA in the absence of any Tribe seeking TAS status) is approximately $160 million in 2010, $100 million in 2015, and $750 million in 2020 (1999$). There are currently three coal-fired Utility Units located in Indian country that will be affected by this rule and the percentage of Indian country that will be impacted is very small. For eligible Tribes that choose to regulate sources in Indian country, the costs would be attributed to inspecting regulated facilities and enforcing adopted regulations.

EPA consulted with Tribal officials in developing this rule. The EPA encouraged Tribal input at an early stage. A Tribal representative from the Navajo Nation was a member the official workgroup and was provided with all workgroup materials. The EPA has provided two briefings for Tribal representatives and the newly formed National Tribal Air Association (NTAA), and other national Tribal forums such as the National Tribal Environmental Council (NTEC) and the National Tribal Forum during the period prior to issuance of the NCR. Another briefing for Tribal representatives, NTAA, and NTEC was provided post-proposal to provide opportunity for additional input. Input from Tribal representatives has been taken into consideration in development of this rule.

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

EO 13045, “Protection of Children from Environmental Health and Safety Risks” (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be “economically significant” as defined under EO 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, Section 5–501 of the EO directs the Agency to evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This final rule is subject to the Executive Order because it is an economically significant regulatory action as defined by Executive Order 12866, and we believe that the environmental health or safety risk addressed by this action may have a disproportionate effect on children. Accordingly, we have evaluated the environmental health or safety effects of this rule on children. The results of this evaluation are discussed elsewhere in this preamble and the RIA, and are contained in the docket.

As discussed in the Regulatory Impact Analysis of the Clean Air Mercury Rule (RIA), EPA and the National Research Council (NRC) of the National Academy of Science (NAS) identified neurodevelopmental effects as the most sensitive endpoints (NRC 2000) and thus the appropriate endpoint upon which to establish a health-based standard establishing the level of exposure to MeHg that would result in a nonappreciable risk. As such, EPA has established its health-based ingestion rate, or reference dose (RfD) at a level designed to protect children prenatally exposed to MeHg. The RfD is an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime (EPA 2002). EPA believes that exposures at or below the RfD are unlikely to be associated with appreciable risk of deleterious effects. It is important to note, however, that the RfD does not define an exposure level corresponding to zero risk; Hg exposure near or below the RfD could pose a very low level of risk which EPA deems to be non-appreciable. It is also important to note that the RfD does not define a bright line, above which individuals are at risk of adverse effect. The CAMR benefits prenatally exposed children by contributing to the reduction in the number of women of childbearing age who ingest Hg at a rate that exceeds the RfD due solely to power plants and by contributing the to the overall reduction in exposure to MeHg of women of childbearing age.

In order to protect prenatally exposed children, it is appropriate to focus on reducing MeHg exposure for women of childbearing age. In the US, the primary means of exposure to MeHg is through the consumption of fish containing MeHg. When emitted, Hg deposits in waterbodies where bacteria in the sediment can convert that Hg in the MeHg which can then bioaccumulate in fish. By reducing the amount of Hg deposition, CAMR reduces the amount of Hg that is available for methylation, which in turn reduces the amount that can be taken up by fish and then consumed by women of childbearing age. This chain of events ultimately reduces exposure to the developing fetus. Thus, EPA's CAMR is specifically targeted at protecting children in their most vulnerable phase - during fetal development.

EPA's ability to reduce exposure by reducing Utility Unit emissions is limited by the fact that emissions from U.S. EGU's are only one source of domestic Hg deposition. Further, the impact of U.S. Utility Unit emissions on fish tissue MeHg concentrations is not likely to be as significant for marine species, which on average accounts for about 63 percent of consumption for the U.S. general population and 60 percent of consumption for U.S. women of childbearing age. Nevertheless, EPA chose a regulatory approach that required Hg-specific reductions of Utility Unit emissions by setting a cap on total emissions in 2018. This Hg-specific cap, combined with the cobenefits associated with reductions of SO_2 and NO_x required by EPA's

Clean Air Interstate Rule, will provide for reduction in MeHg exposure to U.S. women of childbearing age.

CAMR will reduce the level of exposures to children from current levels today. In Section 11 of the RIA, we estimate that 529,000 to 825,000 children will be exposed to MeHg prenatally in 2020. Our RIA analyses assess how IQ decrements, which were used as a surrogate representing the neurodevelopmental effects of MeHg exposure, will be reduced as a result of CAMR. Because these analyses only quantitatively assess benefits in terms of IQ loss, the overall quantified benefit to the prenatally exposed children is likely to be understated. Compared to the other regulatory alternative considered during this rulemaking, the selected approach delivers about the same amount of benefits at a lower cost.

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

EO 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.

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. The rule uses cost-effective, 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

SO_2 and NO_X cap levels under CAIR. Although the Administration has sought 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.

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 SO_2 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) (OAR-2002-0056).

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Public Law No. 104-113; Section 12(d), 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable VCS.

This final rule involves technical standards. The EPA methods cited in this rule are: 1, 1A, 2, 2A, 2C, 2D, 2F, 2G, 2H, 3, 3A, 3B, 4, 6, 6A, 6C, 7, 7A, 7C, 7D, 7E, 19, 20, and 29 (for Hg only) of 40 CFR part 60, appendix A; Performance Specifications (PS) 2 and 12A of 40 CFR part 60, appendix B; 40 CFR part 75, appendix K; and ASTM D6784-02, “Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury Gas Generated from Coal-Fired

Stationary Sources (Ontario-Hydro Method).”

Consistent with the NTTAA, EPA conducted searches to identify VCS in addition to these EPA methods/performance specifications. No applicable VCS were identified for EPA Method 1A, 2A, 2D, 2F, 2G, 2H, 7D, and 19, of 40 CFR part 60, appendix A; 40 CFR part 75, appendix K; and ASTM D6784-02. The search and review results have been documented and are placed in the docket for the final rule.

One VCS was identified as an acceptable alternative for the EPA methods cited in this rule. The VCS ASME PTC 19-10-1981-Part 10, “Flue and Exhaust Gas Analyses,” is cited in this rule for its manual method for measuring the oxygen, carbon dioxide (CO_2), SO_2, and NO_x content of exhaust gas. These parts of ASME PTC 19-10-1981-Part 10 are acceptable alternatives to EPA Methods 3B, 6, 6A, 7, 7C, and 20 (SO_2 only).

The standard ASTM D6784-02, “Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury Gas Generated from Coal-Fired Stationary Sources (Ontario-Hydro Method), cited in this rule for measuring Hg emissions is a VCS.

In addition to the VCS EPA uses in the final rule, the search for emissions measurement procedures identified 14 other VCS. The EPA determined that 12 of these 14 standards identified for measuring air emissions or surrogates subject to emission standards in the final rule were impractical alternatives to EPA test methods/performance specifications for the purposes of the rule. Therefore, the EPA does not intend to adopt these standards. The reasons for the determinations of these 12 standards are discussed below.

The VCS ASTM D3154-00, “Standard Method for Average Velocity in a Duct (Pitot Tube Method),” is not acceptable as an alternative to EPA Methods 1, 2, 2C, 3, 3B, and 4. This standard appears to cover the scope of EPA Methods 1, 2, 2C, 3, 3B, and 4, but lacks in QA/QC requirements. Specifically, ASTM D3154-00 does not include the following: (1) proof that openings of standard pitot tube have not plugged during the test; (2) if differential pressure gauges other than inclined manometers (e.g., magnehelic gauges) are used, their calibration must be checked after each test series; and (3) the frequency and validity range for calibration of the temperature sensors.

The VCS ASTM D3464-96 (2001), “Standard Test Method Average Velocity in a Duct Using a Thermal Anemometer,” is not acceptable as an alternative to EPA Method 2. The applicability specifications in this ASTM standard are not clearly defined, e.g., range of gas composition, temperature limits. Also, the lack of supporting QA data for the calibration procedures and specifications, and certain variability issues that are not adequately addressed by the standard limit EPA’s ability to make a definitive comparison of the method in these areas.

The VCS ISO 10780:1994, “Stationary Source Emissions--Measurement of Velocity and Volume Flowrate of Gas Streams in Ducts,” is not acceptable as an alternative to EPA Method 2. ISO 10780:1994 recommends the use of an L-shaped pitot, which historically has not been recommended by EPA. The EPA specifies the S-type design which has large openings that are less likely to plug up with dust.

The VCS ASME PTC 19-10-1981-Part 10, “Flue and Exhaust Gas Analyses,” is not acceptable as an alternative to EPA Methods 3A, 6C, 7A, 7B, 7E, and 20 (NO_x and oxygen). This ASME standard includes manual and instrumental methods of analyses for CO_2, carbon monoxide, hydrogen sulfide, NO_x, oxygen, and SO_2. The analytes in the standard that are measured by one or more of the same instrumental techniques as in the EPA methods (in parentheses) are as follows: CO_2 (3A); NO_x (7A, 7B, 7E, 20), oxygen (3A, 20); and SO_2 (6C). For the standard’s instrumental procedures, only general descriptions of the procedures are included which are not true methods. Therefore, while some of the manual methods are acceptable alternatives to the corresponding EPA methods, the instrumental procedures are not.

The VCS ISO 10396:1993 “Stationary Source Emissions: Sampling for the Automated Determination of Gas Concentrations,” is not acceptable as an alternative to EPA Methods 3A, 6C, 7E, and 20 (nitrogen oxides and oxygen parts only). This standard is similar to EPA Methods 3A, 6C, 7E, and 20 (NO_x and oxygen parts only), but lacks in detail and quality assurance/quality control requirements. Specifically, ISO 10396 does not include the following: (1) sensitivity of the method; (2) acceptable levels of analyzer calibration error; (3) acceptable levels of sampling system bias; (4) zero drift and calibration drift limits, time span, and required testing frequency; (5) a method to test the interference response of the analyzer; (6) procedures to determine the minimum sampling time per run and minimum measurement time; and (7) specifications for data recorders, in terms of resolution (all types) and recording intervals (digital and analog recorders, only). This standard is also very similar to ASTM D5835.

The VCS ISO 12039:2001 “Stationary Source Emissions--Determination of Carbon Monoxide, Carbon Dioxide, and Oxygen--Automated Methods,” is not acceptable as an alternative to EPA Methods 3A and 20 (oxygen portion only). This method is similar to the EPA methods, however, ISO 12039 is missing some key features. In terms of sampling, the hardware required by ISO 12039 does not include a 3-way calibration valve assembly or equivalent to block the sample gas flow while calibration gases are introduced. In its calibration procedures, ISO 12039 only specifies a two-point calibration while the EPA methods specify a 3-point calibration. Also, ISO 12039 does not specify performance criteria for calibration error, calibration drift, or sampling system bias tests, although checks of these QC features are required by the ISO standard.

The VCS ASTM D5835-95 (2001), “Standard Practice for Sampling Stationary Source Emissions for Automated Determination of Gas Concentration,” is not acceptable as an alternative to EPA Methods 3A, 6C, 7E, and 20 (NO_x and oxygen parts only). This standard is similar to the EPA methods, but lacks in detail and QA/QC requirements. Specifically, ASTM D5835-95 does not include the following: (1) sensitivity of the method; (2) acceptable levels of analyzer calibration error; (3) acceptable levels of sampling system bias; (4) zero drift and calibration drift limits, time span, and required testing frequency; (5) a method to test the interference response of the analyzer; (6) procedures to determine the minimum sampling time per run and minimum measurement time; and (7) specifications for data recorders, in terms of resolution (all types) and recording intervals (digital and analog recorders, only). This standard is also very similar to ISO 10396.

The VCS CAN/CSA Z223.2-M86 (1999) “Method for the Continuous Measurement of Oxygen, Carbon Dioxide, Carbon Monoxide, Sulphur Dioxide, and Oxides of Nitrogen in Enclosed Combustion Flue Gas Streams,” is not acceptable as a substitute for EPA Methods 3A, 6C, 7E, and 20 (NO_x and oxygen parts only), since it does not include quantitative specifications for measurement system performance, most notably the calibration procedures and instrument performance characteristics. The instrument performance characteristics that are provided in this Canadian standard are nonmandatory and also do not provide the same level of QA as the EPA methods. For example, the zero and span/calibration drift is only checked weekly, whereas the EPA methods requires drift checks after each run.

The VCS EN 13211:2001, “Air Quality--Stationary Source Emissions--Determination of the Concentration of Total Mercury,” is not acceptable as an alternative to the Hg portion of EPA Method 29 primarily because it is not validated for use with impingers, as in the EPA method, although the standard describes procedures for the use of impingers. This European standard is validated for the use of fritted bubblers only and requires the use of a side (split) stream arrangement for isokinetic sampling because of the low sampling rate of the bubblers (up to 3 liters per minute, maximum). Also, only two bubblers (or impingers) are required by EN 13211, whereas EPA Method 29 require the use of six impingers. In addition, EN 13211 does not include many of the quality control procedures of EPA Method 29, especially for the use and calibration of temperature sensors and controllers, sampling train assembly and disassembly, and filter weighing.

The VCS CAN/CSA Z223.26-M1987, “Measurement of Total Mercury in Air Cold Vapour Atomic Absorption

Spectrophotometeric Method," is not acceptable as an alternative to the cold vapor atomic absorption spectrometry (CVAAS) analytical procedure of EPA Method 29 (Hg only) because of lack of detail in QC. Specifically, CAN/CSA Z223.26 does not include specifications for the number of calibration samples to be analyzed, procedures to prevent carryover from one sample to the next, and procedures for subtraction of the instrument response to calibration blank as in the EPA method. Also, CAN/CSA Z223.26 does not require that the calibration curve be forced through or close to zero (or a point no further than ± 2 percent of the recorder full scale) as in the EPA method. CAN/CSA Z223.26 also does not include a procedure to assure that two consecutive peak heights agree within 3 percent of their average value and that the peak maximum is greater than 10 percent of the recorder full scale, as in the EPA method. And, CAN/CSA Z223.26 does not include instructions for a blank and a standard to be run at least every five samples, nor specifications for the peak height of the blank and the standard as in the EPA method.

The VCS ISO 10849:1996 "Determination of the Mass Concentration of Nitrogen Oxides-Performance Characteristics of Automated Measuring Systems," is not acceptable as an alternative to EPA PS 2 (NO_x portion only) because it is missing key components included in the EPA PS, as follows: (1) the calibration drift performance specification of EPA

PS 2 is not one of the main performance specifications of the VCS and the allowable value for the drift is offered as a “guideline” in an “informative” appendix rather than in a required section of the standard. Also, the standard requires that the calibration drift checks only be made at “regular” intervals rather than the specified 24-hour checks of PS 2; (2) the standard does not specify the measurement locations and traverse points needed to obtain a representative sample for the performance tests; (3) no specifications are included for data recorder use or operation; (4) the high level values used to calibrate the CEMS in the standard are derived from the instrument scale and not the maximum potential emissions at the source, as in EPA PS 2; and (5) the standard does not require moisture measurement or show how to correct results for moisture as in PS 2, nor does it show how to standardize to a specific diluent concentration (e.g., 7 percent oxygen).

The VCS, prEN 14884 (draft January 2004) “Air Quality--Stationary Source Emissions–Determination of Total Mercury: Automated measuring Systems” is not acceptable as an alternative to PS 12A because it is not specifically intended as a method for measurement of gaseous Hg. Also, prEN 14884 is missing some critical QA measures that are included in PS 12A. The standard prEN 14884 also specifies using a linear regression of the reference method (RM) and CEMS data to report CEMS results during normal operation, whereas PS 12A uses the RM results as a QC criteria for improper CEMS installation when the CEMS data is greater than 20 percent of the mean RM data or 10 percent of the applicable standard. Other deficiencies in this European standard are as follows: (1) prEN 14884 only requires two (zero and span) of the three reference gas concentrations (zero, mid-level, and high-level) required by PS 12A to determine the measurement error; (2) prEN 14884 is missing much of the detail of PS 12A as in, for example, the siting of the CEMS, reference gas delivery system design, data recorder ranges and response, and correlation of the RM and CEMS stack conditions during RA tests; and (3) prEN 14884 does not require as many RM tests as PS 12A and has a shorter minimum sampling period. Also, PrEN 14884 only requires 15 single tests as compared to the 9 paired tests (18 total) in PS 12A, and prEN 14884 allows as little as 7.5 hours of sampling time (with 8 to 10 hours recommended) as compared to the minimum of 18 hours sampling time in PS 12A.

Two of the 14 VCS identified in this search were not available at the time the review was conducted for the purposes of the rule because they are under development by a voluntary consensus body: ASME/BSR MFC 12M, “Flow in Closed Conduits Using Multiport Averaging Pitot Primary Flowmeters,” for EPA Method 2, and ASME/BSR MFC 13M, “Flow Measurement by Velocity Traverse,” for EPA Method 2 (and possibly 1).

40 CFR 60.49a, 40 CFR part 75, and PS 12A of the CAMR discuss the EPA testing methods, performance specifications, and procedures required. Under 40 CFR 63.7(f) and 63.8(f) of subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures.

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

EO 12898, “Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations,” requires Federal agencies to consider the impact of programs, policies, and activities on minority populations and low-income populations. According to EPA guidance,[12] agencies are to assess whether minority or low-income populations face risks or a rate of exposure to hazards that are significant and that “appreciably exceed or is likely to appreciably exceed the risk or rate to the general population or to the appropriate comparison group.” (EPA, 1998)

In accordance with EO 12898, the Agency has considered

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[12] U.S. Environmental Protection Agency, 1998. Guidance for Incorporating Environmental Justice Concerns in EPA’s NEPA Compliance Analyses. Office of Federal Activities, Washington, D.C., April, 1998.

whether this rule may have disproportionate negative impacts on minority or low income populations. The Agency expects this rule to lead to beneficial reductions in air pollution and exposures generally with a small negative impact through increased utility bills. The increase in the price for electric power is estimated to be 0.2 percent of retail electricity prices and is shared among all members of society equally and thus is not considered to be a disproportionate impact on minority populations and low-income populations. For this reason, negative impacts to these sub-populations that appreciably exceed similar impacts to the general population are not expected.

There will be beneficial outcomes to these populations as a result of this action. In the absence of CAMR, there are health effects that are likely to affect certain populations in the U.S., including subsistence anglers, Native Americans, and Asian American. These populations may include low income and minority populations who are disproportionately impacted by Hg exposures due to their economic, cultural, and religious activities that lead to higher levels of consumption of fish than the general population. The CAMR is expected to reduce exposures to these populations.

For subsistence anglers, we conducted an analysis in Section 10 of the RIA using two alternative approaches to determine potentially exposed subsistence anglers, including one analytical approach based on income (i.e., the population below $10,000 annual income who may eat self-caught fish as a means of obtaining a low-cost source of protein), and another analytical approach based on total consumption levels (i.e., those anglers who eat 2 to 3 fish meals per day are assumed to be subsistence). Our analysis shows that the final rule will result in total benefits (under a scenario of no threshold on effects at low doses of Hg) accrued to potentially prenatally exposed children in the homes of subsistence anglers of $454,000 to $573,000 in 2020 when using a 3 percent discount rate (or $212,000 to $391,000 when using a 7 percent discount rate).

We also conducted case studies of the potential benefits of CAMR to a Native American population and an Asian American population located in Wisconsin, Minnesota, and (for one of the case studies) Michigan. The Agency was unable to transfer the results of these case studies to the rest of the Native American and Asian American populations in the U.S. due to missing data elements for analysis in other parts of the country.

In the case study of the Chippewa in Minnesota, Wisconsin, and Michigan, we determined that this group would accrue total benefits (under an assumption of no threshold on effects at low doses of Hg) of $6,300 to $6,700 in 2020 when using a 3 percent discount rate across the group as a whole (or $3,000 to $4,600 when using a 7 percent discount rate) due to reduced Hg exposures from consuming self-caught freshwater fish. Other tribal populations were not evaluated due to lack of reliable data on yearly (annual) self-caught fish consumption by location and tribe (although they were considered in a sensitivity analysis examining the issue of distributional equity - see below).

In a case study of the Hmong (a Southeast Asian-American population) in Minnesota and Wisconsin, we determined that the population would accrue total benefits (under an assumption of no threshold on effects at low doses of Hg) of $3,300 to $3,500 when using a 3 percent discount rate (or $1,500 to $2,400 when using a 7 percent discount rate).

To further examine whether high fish-consuming (subsistence) populations might be disproportionately benefitted by the rule (i.e., whether distributional equity is a consideration) and in response to concerns received in the comments on the NODA regarding high fish consumption rates for Ojibwe in the Great Lakes area, EPA conducted a sensitivity analysis focusing specifically on the distributional equity issue. The sensitivity analysis applied high-end (near bounding) fish consumption rates for Native American subsistence populations to the maximum expected Hg fish-tissue concentration changes predicted to result from CAMR within regions of the 37-State study area with recognized Native American populations. The fish consumption rates used in this sensitivity analysis were based on comments received through the NODA characterizing high-end consumption for the Ojibwe Tribes in Wisconsin and Minnesota. These values represent very high consumption rates exceeding the high-end (95th percentile) consumption rates recommended by the EPA for Native American subsistence populations and consequently are appropriate for a sensitivity analysis. The sensitivity analysis suggested that, although Native American subsistence populations (and other high fish consuming populations) might experience relatively larger health benefits from this rule compared with general recreational angler, the absolute degree of health benefits involved are relatively low (i.e., less than a 1.0 IQ point change per fisher for any of the locations modeled). This sensitivity analysis also provided coverage for the Hmong population modeled for the RIA and the conclusions cited above regarding relatively low IQ changes (less than 1.0) can also be applied to this high fish consuming population.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by SBREFA of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the U.S. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the Federal Register. A Major rule cannot take effect until 60 days after it is published in the Federal Register. The final rule is a “major rule” as defined by 5 U.S.C. 804(2).

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

For the reasons stated in the preamble, title 40, chapter I, parts 60, 63, 72, and 75 of the Code of the Federal Regulations are amended as follows:

PART 60–[AMENDED]

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

Authority: 42 U.S.C. 7401, 7403, 7426, and 7601.

2. Section 60.17 amended by, in paragraph (a)(12), replacing the words “§§60.41(f),” by the words “§§60.24(h)(8)(v), 60.41(f),” and replacing the words “and 60.251(b) and (c).” by the words “60.251(b)and (c), and 60.4101.” and by adding paragraph (a)(65) to read as follows:

§60.17 Incorporations by Reference.

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(a)* * *

(65) ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario-Hydro Method), for appendix B to part 60, Performance Specification 12A.

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3. Section 60.21 is amended by:

a. Revise paragraphs (a) and (f); and

b. Add a new paragraph (k) to read as follows:

<u>§60.21 Definitions</u>.

*   *   *   *   *

(a) <u>Designated pollutant</u> means any air pollutant, the emissions of which are subject to a standard of performance for new stationary sources, but for which air quality criteria have not been issued and that is not included on a list published under section 108(a) of the Act. Designated pollutant also means any air pollutant, the emissions of which are subject to a standard of performance for new stationary sources, that is on the section 112(b)(1) list and is emitted from a facility that is not part of a source category regulated under section 112. Designated pollutant does not include pollutants on the section 112(b)(1) list that are emitted from a facility that is part of a source category regulated under section 112.

*   *   *   *   *

(f) <u>Emission standard</u> means a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions.

*   *   *   *   *

(k) <u>Allowance system</u> means a control program under which the owner or operator of each designated facility is required to hold an authorization for each specified unit of a designated pollutant emitted from that facility during a specified period and which limits the total amount of such authorizations available to be held for a designated pollutant for a specified period and allows the transfer of such authorizations not used to meet the authorization-holding requirement.

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4. Section 60.24 is amended by:

a. Revise paragraph (b)(1); and

b. Add a new paragraph (h) to read as follows:

§60.24 Emission standards and compliance schedules.

(a) * * *

(b)(1) Emission standards shall either be based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable. * * *

* * * * *

(h) Each of the States identified in paragraph (h)(1) of this section shall be subject to the requirements of paragraphs (h)(2) through (7) of this section.

(1) Alaska, Alabama, Arkansas, Arizona, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana,

Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and the District of Columbia shall each, and, if approved for treatment as a State under part 49 of this chapter, the Navajo Nation and the Ute Indian Tribe may each, submit a State plan meeting the requirements of paragraphs (h)(2) through (7) of this section and the other applicable requirements for a State plan under this subpart.

(2) The State's State plan under paragraph (h)(1) of this section must be submitted to the Administrator by no later than **[INSERT DATE 18 MONTHS (548 days) FROM THE DATE ON WHICH THE ADMINISTRATOR SIGNS THE FINAL CAMR]**. The State shall deliver five copies of the State plan to the appropriate Regional Office, with a letter giving notice of such action.

(3) The State's State plan under paragraph (h)(1) of this section shall contain emission standards and compliance schedules and demonstrate that they will result in compliance with the State's annual electrical generating unit (EGU) mercury (Hg) budget for the appropriate periods.

The amount of the annual EGU Hg budget, in tons of Hg per year, shall be as follows, for the indicated State for the indicated period:

State	**Annual EGU Hg 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
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
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
Navajo Nation Indian country	0.601	0.237
Ute Indian Tribe Indian country	0.06	0.024

(4) Each State plan under paragraph (h)(1) of this section shall require EGUs to comply with the monitoring, record keeping, and reporting provisions of part 75 of this chapter with regard to Hg mass emissions.

(5) In addition to meeting the requirements of §60.26, each State plan under paragraph (h)(1) of this section must show that the State has legal authority to:

(I) Adopt emissions standards and compliance schedules necessary for attainment and maintenance of the State’s relevant annual EGU Hg budget under paragraph (h)(3) of this section; and

(ii) Require owners or operators of EGUs in the State to meet the monitoring, record keeping, and reporting requirements described in paragraph (h)(4) of this section.

(6)(I) Notwithstanding the provisions of paragraphs (h)(3) and (5)(i) of this section, if a State adopts regulations substantively identical to subpart HHHH of this part (Hg Budget Trading Program), incorporates such subpart by reference into its regulations, or adopts regulations that differ substantively from such subpart only as set forth in paragraph (h)(6)(ii) of this section, then such allowance system in the State's State plan is automatically approved as meeting the requirements of paragraph (h)(3) of this section, provided that the State demonstrates that it has the legal authority to take such action and to implement its responsibilities under such regulations.

(ii) If a State adopts an allowance system that differs substantively from subpart HHHH of this part only as follows, then the emissions trading program is approved as set forth in paragraph (h)(6)(i) of this section.

(A) The State may decline to adopt the allocation provisions set forth in §§60.4141 and 60.4142 of this chapter and may instead adopt any methodology for allocating Hg allowances.

(B) The State's methodology under paragraph (h)(6)(ii)(A) of this section must not allow the State to allocate Hg allowances for a year in excess of the amount in the State's annual EGU Hg budget for such year under paragraph (h)(3) of this section;

(C) The State's methodology under paragraph (h)(6)(ii)(A) of this section must require that, for EGUs commencing operation before January 1, 2001, the State will determine, and notify the Administrator of, each unit’s allocation of Hg allowances by October 31, 2006 for 2010, 2011, and 2012 and by October 31, 2009 and October 31 of each year thereafter for the fourth year after the year of the notification deadline; and

(D) The State’s methodology under paragraph (h)(6)(ii)(A) of this section must require that, for EGUs commencing operation on or after January 1, 2001, the State will determine, and notify the Administrator of, each unit’s allocation of Hg allowances by October 31 of the year for which the Hg allowances are allocated.

(7) If a State adopts an allowance system that differs substantively from subpart HHHH of this part, other than as set forth in paragraph (h)(6)(ii) of this section, then such allowance system is not automatically approved as set forth in paragraph (h)(6)(i) or (ii) of this section and will be reviewed by the Administrator for approvability in accordance with the other provisions of paragraphs (h)(2) through (5) of this section and the other applicable requirements for a State plan under this subpart, provided that the Hg allowances issued under such allowance system shall not, and the State plan under paragraph (h)(1) of this

section shall state that such Hg allowances shall not, qualify as Hg allowances under any allowance system approved under paragraph (h)(6)(i) or (ii) of this section.

(8) The terms used in this paragraph (h) shall have the following meanings:

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator’s duly authorized representative.

Allocate or allocation means, with regard to Hg allowances, the determination of the amount of Hg allowances to be initially credited to a source.

Boiler means an enclosed fossil- or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90, 91, 95, or 98a (incorporated by reference).

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year.

Cogeneration unit means a stationary, coal-fired boiler or stationary, coal-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

<u>Combustion turbine</u> means:

(1) An enclosed device comprising a compressor, a combustion, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustion passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

<u>Commence operation</u> means to have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit’s combustion chamber.

<u>Electric generating unit</u> or <u>EGU</u> means:

(1) Except as provided in paragraph (2) of this definition, a stationary, coal-fired boiler or stationary, coal-fired combustion turbine in the State serving at any time, since the start-up of a unit’s combustion chamber, a generator with nameplate capacity of more than 25 megawatts electric (MW) producing electricity for sale.

(2) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit

first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit in the State serving at any time a generator with nameplate capacity of more than 25 MW 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 during the 12-month period 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 definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

<u>Generator</u> means a device that produces electricity.

<u>Gross electrical output</u> means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

<u>Gross thermal energy</u> means, with regard to a cogeneration unit, useful thermal energy output plus, where such output is made available for an industrial or commercial process, any heat contained in condensate return

or makeup water.

Heat input means, with regard to a specified period of time, the product (in million British thermal units per unit time, MMBTU/time) of the gross calorific value of the fuel (in Btu per pound, Btu/lb) divided by 1,000,000 Btu/MMBTU and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the Hg designated representative and determined by the Administrator in accordance with §§60.4170 through 60.4176 and excluding the heat derived from preheated combustion air, reticulated flue gases, or exhaust from other sources.

Hg allowance means a limited authorization issued by the permitting authority to emit one ounce of Hg during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy from any specified unit and pays its proportional amount of such unit’s total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady-state basis as specified by the manufacturer of the unit, or, starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu per hour, Btu/hr) that a unit is capable of combusting on a steady-state basis, such decreased maximum amount as specified by the person conducting the physical change.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MW) that the generator is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other derates) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MW) that the generator is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other derates), such increased maximum amount as specified by the person conducting the physical change.

<u>Operator</u> means any person who operates, controls, or supervises an EGU or a source that includes an EGU and shall include, but not be limited to, any holding company, utility system, or plant manager of such EGU or source.

<u>Ounce</u> means 2.84 x 10^7 micrograms.

<u>Owner</u> means any of the following persons:

(1) With regard to a Hg Budget source or a Hg Budget unit at a source, respectively:

(I) Any holder of any portion of the legal or equitable title in a Hg Budget unit at the source or the Hg Budget unit;

(ii) Any holder of a leasehold interest in a Hg Budget unit at the source or the Hg Budget unit; or

(iii) Any purchaser of power from a Hg Budget unit at the source or the Hg Budget unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such Hg Budget unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the Hg allowances held in the general account and who is subject to the binding agreement for the Hg authorized account representative to represent the person’s ownership interest with respect to Hg allowances.

Potential electrical output capacity means 33 percent of a unit’s maximum design heat input, divided by 3,413 Btu per kilowatt-hour (Btu/kWh), divided by 1,000 kWh per megawatt-hour (kWh/MWh), and multiplied by 8,760 hr/yr.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons.

State means:

(1) For purposes of referring to a governing entity, one of the States in the United States, the District of Columbia, or, if approved for treatment as a State under part 49 of this chapter, the Navajo Nation or Ute Indian Tribe that adopts the Hg Budget Trading Program pursuant to §60.24(h)(6) of this chapter; or

(2) For purposes of referring to a geographic area, one of the States in the United State, the District of Columbia, the Navajo Nation Indian country, or the Ute Tribe Indian country.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary coal-fired boiler or a stationary coal-fired combustion turbine.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heat application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

Subpart Da–[AMENDED]

5. Section 60.41a is amended by revising the definition of “Electric utility steam generating unit,” and

by adding in alphabetical order the definitions of “Bituminous coal,” “Coal,” “Coal-fired electric utility steam generating unit,” “Cogeneration,” “Electric utility steam generating unit,” “Electrostatic precipitator,” “Emission limitation,” “Emission rate period,” “Federally enforceable,” “Gaseous fuel,” “Integrated gasification combined cycle electric utility steam generating unit,” “Natural gas,” and “Responsible official” to read as follows:

§60.41a Definitions.

* * * * *

Bituminous coal means coal that is classified as bituminous according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, or 98a (incorporated by reference — see §60.17).

* * * * *

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, or 98a, (incorporated by reference — see §60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

<u>Coal-fired electric utility steam generating unit</u> means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other supplemental fuels in any amount. Examples of supplemental fuels include, but are not limited to, petroleum coke and tire-derived fuels.

* * * * *

<u>Cogeneration</u> means a facility that simultaneously produces both electrical (or mechanical) and useful thermal energy from the same primary energy source.

* * * * *

<u>Dry flue gas desulfurization technology</u> or <u>dry FGD</u> means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries

or solutions used in dry FGD technology include, but are not limited to, lime and sodium.

* * * * *

Electric utility steam generating unit means any fossil fuel-fired combustion unit of more than 25 megawatts electric (MW) 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 MW output to any utility power distribution system for sale is also considered an electric utility steam generating unit.

Electrostatic precipitator or ESP means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

* * * * *

Emission limitation means any emissions limit or operating limit.

Emission rate period means any calendar month included in a 12-month rolling average period.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or 40 CFR 51.18 and 40 CFR 51.24.

*   *   *   *   *

Gaseous fuel means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, and coke-oven gas.

*   *   *   *   *

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

*   *   *   *   *

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth’s surface, of which the principal constituent is methane; or (2) liquid petroleum gas, as defined by the American Society of Testing and Materials (ASTM) Standard Specification for Liquid Petroleum Gases D1835–82, 86, 87, 91, or 97, (Incorporated by reference — see §60.17).

*   *   *   *   *

Responsible official means responsible official as defined in 40 CFR 70.2.

* * * * *

Wet flue gas desulfurization technology or _wet FGD_ means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet FGD technology include, but are not limited to, lime, limestone, and sodium.

* * * * *

6. Subpart Da is amended by:

a. Predesignate §60.49a as §60.51a;

b. Predesignate §60.48a as §60.50a;

c. Predesignate §60.47a as §60.49a;

d. Predesignate §60.46a as §60.48a;

e. Predesignate §60.45a as §60.47a; and

f. Adding new §§60.45a and 60.46a to read as follows:

§60.45a Standard for Mercury.

(a) For each coal-fired electric utility steam generating unit other than an integrated gasification combined cycle (ICC) electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction or reconstruction commenced after January 30, 2004, any gases which contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average using the procedures in §60.50a(h).

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 21×10^{-6} pound per megawatt hour (lb/MWh) or 0.021 lb/gigawatt-hour (GWh) on an output basis. The International System of Units (SI) equivalent is 0.0026 nanograms per joule (ng/J).

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal:

(i) If you utilize wet FGD technology to limit SO_2 emissions from your steam generating unit, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 42 x 10^{-6} lb/MWh or 0.042 lb/GWh on an output basis. The SI equivalent is 0.0055 ng/J.

(ii) If you utilize dry FGD technology to limit SO_2 emissions from your steam generating unit, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 78 x 10^{-6} lb/MWh or 0.078 lb/GWh on an output basis. The SI equivalent is 0.0103 ng/J.

(3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 145 x 10^{-6} lb/MWh or 0.145 lb/GWh on an output basis. The SI equivalent is 0.0183 ng/J.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 1.4 x 10^{-6} lb/MWh or 0.0014 lb/GWh on an output basis. The SI equivalent is 0.00017 ng/J.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different

coal ranks (i.e., bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the monthly unit-specific Hg emissions limit established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to the affected unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the proportion of energy output (in British thermal units, Btu) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total Btu or megawatt hours contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^{n} EL_i\left(HH_i\right)}{\sum_{i=1}^{n} HH_i} \qquad \text{(Eq. 1)}$$

Where:

EBB = Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged under the blending provision.

Eli = Hg emissions limit for the subcategory i (coal rank) that applies to affected source, lb/MWh.

H.I. = Electricity output from affected source during the production period related to use of the corresponding subcategory i (coal rank) that falls within the compliance period, gross MWh generated by the electric utility steam generating unit.

n = Number of subcategories (coal ranks) being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated, supplementary fuels, you must not discharge into the atmosphere any gases from the unit that contain Hg in excess of the computed weighted Hg emission limit based on the proportion of electricity output (in MWh) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total megawatt hours contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each ICC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction or reconstruction commenced after January 30, 2004, any gases which contain Hg emissions in excess of 20 x 10^{-6} lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average using the procedures in §60.50a(g).

<u>§60.46a (Reserved)</u>.

7. Newly predesignated §60.48a is amended by:

a. Revising paragraph (c);

b. In paragraph (h) by revising the existing references from “§60.47a” to “§60.49a”;

c. In paragraph (i) by revising the existing references for “§§60.47a(c),” “60.47a(l),” and “60.47a(k)” to “§§60.49a(c),” “60.49a(l),” and “60.49a(k),” respectively;

d. In paragraph (j)(2) by revising the existing references from “§60.47a” to “§60.49a” twice;

e. In paragraph (k)(2)(ii) by revising the existing references from “§60.47a” and “60.47a(l)” to “§60.49a” and “60.49a(l),” respectively; in paragraph (k)(2)(iii) by revising the existing references from “§60.47a(k)” to “§60.49a(k)”; and in paragraph (k)(2)(iv) by revising the existing references from “§60.47a(l)” to “§60.49a(l)”; and

f. Adding new paragraph (m).

The revision and additions read as follows:

§60.48a Compliance provisions.

* * * * *

(c) The particulate matter emission standards under §60.42a, the nitrogen oxides emission standards under §60.44a, and the Hg emission standards under §60.45a apply at all times except during periods of startup, shutdown, or malfunction.

* * * * *

(m) Compliance provisions for sources subject to §60.45a. The owner or operator of an affected facility subject to §60.45a (new sources constructed or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of §60.49a(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of §60.49a(l) or (m), and hourly gross electrical outputs, determined according to the provisions in §60.49a(k). Compliance with the applicable standard under §60.45a is determined on a 12-month rolling average basis.

8. Newly predesignated §60.49a is amended by:

a. In paragraph (c)(2) by revising the existing references from "§60.49a" to "§60.51a" twice;

b. In paragraph (g) by revising the existing reference from "§60.46a" to "§60.48a" and

c. Adding new paragraphs (p) through (s).

The revision and additions read as follows:

<u>§60.49a Emission monitoring</u>.

* * * * *

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in §60.45a shall install and operate a continuous emissions monitoring system (CEMS) to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to §75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of §60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in §60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in §60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49a(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49a(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in §72.2 of this chapter) to monitor Hg concentration, according to the procedures described in §75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of §75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in §75.11(b) or §75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance

criteria (e.g., calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing record keeping and reporting procedures in accordance with the requirements of this subpart.

9. Newly predesignated §60.50a is amended by:

a. In paragraph (c)(5) by revising the existing references from "§60.47a(b) and (d)" to "§60.49a(b) and (d)," respectively;

b. In paragraph (d)(2) by revising the existing references from "§60.47a(c) and (d)" to "§60.49a(c) and (d)," respectively;

c. In paragraph (e)(2) by revising the existing reference from "§60.46a(d)(1)" to "§60.48a(d)(1)"; and

d. Adding new paragraphs (g) through (i).

The additions read as follows:

§60.50a Compliance determination procedures and methods.

* * * * *

(g) For the purposes of determining compliance with the emission limits in §§60.45a and 60.46a, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus half of the equivalent electrical energy in the unit’s process stream.

(1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (i.e., 250 million Btu/hr input to a electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit); 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 million Btu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).

(2) Use Equation 1 below in lieu of Equation 5 in paragraph (h) of this section, to determine the monthly average Hg emission rates for a cogeneration unit.

$$ER_{cogen} = \frac{M}{\left(\left(V_{grid} \right) + \left(\frac{V_{process}}{2} \right) \right)} \qquad \text{(Eq. 1)}$$

Where:

ER_{COGEN} = Cogeneration Hg emission rate for a particular month (lb/MWh;

M = Mass of Hg emitted from the stack over the same month, from Equation 2 or Equation 3 in paragraph h of this section (lb);

$_{Grid}$ = Amount of energy sent to the grid over the same month (MWh); and

$_{Process}$ = Amount of energy converted to steam for process use over the same month (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in §60.45a according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in §60.8(a). The required continuous monitoring systems must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the continuous monitoring systems for 12 successive months of unit operation (excluding hours of unit startup, shutdown and malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or (h)(3) of this section, as applicable. If, for any month in the initial performance test, the minimum data capture requirement in §60.49a(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first

such month, the substitute monthly Hg emission rate shall be the arithmetic average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in pounds (lb), using either Equation 2 in paragraph (h)(2)(i)(A) of this section or Equation 3 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 4 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 2 below to calculate the Hg mass emissions for each valid hour:

$$E_h = K\, C_h\, Q_h\, t_h \qquad \text{(Eq. 2)}$$

Where:

E_h = Hg mass emissions for the hour, (lb)
K = Units conversion constant, 6.24 x 10^{-11} lb-scm/:g-scf
C_h = Hourly Hg concentration, wet basis, (:g/scm)
Q_h = Hourly stack gas volumetric flow rate, (scfh)
t_h = Unit operating time, i.e., the fraction of the hour for which the unit operated. For example, t_h = 0.50 for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use Equation 3 below to calculate the Hg mass emissions for each valid hour:

$$E_h = K\, C_h\, Q_h\, t_h\, (1-B_{ws}) \qquad \text{(Eq. 3)}$$

Where:

E_h = Hg mass emissions for the hour, (lb)
K = Units conversion constant, 6.24 x 10^{-11} lb-scm/:g-scf
C_h = Hourly Hg concentration, dry basis, (:g/dscm)
Q_h = Hourly stack gas volumetric flow rate, (scfh)
t_h = Unit operating time, i.e., the fraction of

the hour for which the unit operated

B_{ws} = Stack gas moisture content, expressed as a decimal fraction (e.g., for 8 percent H_2O, $B_{ws} = 0.08$)

(C) Use Equation 4, below, to calculate M, the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 2 or 3 (as applicable):

$$M = \sum_{h=1}^{n} E_h \qquad \text{(Eq. 4)}$$

Where:

M = Total Hg mass emissions for the month, (lb)

E_h = Hg mass emissions for hour "h", from Equation 2 or 3 of this section, (lb)

n = The number of unit operating hours in the month with valid CEM and electrical output data, excluding hours of unit startup, shutdown and malfunction

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 5, below. For a cogeneration unit, use Equation 1 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \qquad \text{(Eq. 5)}$$

Where:

ER = Monthly Hg emission rate, (lb/MWh)

M = Total mass of Hg emissions for the month, from Equation 4, above, (lb)

P = Total electrical output for the month, for the hours used to calculate M,(MWh)

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 6 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=i}^{12} (ER)_i \, n_i}{\sum_{i=i}^{12} n_i} \qquad \text{(Eq. 6)}$$

Where:

E_{avg} = Weighted 12-month rolling average Hg emission rate, (lb/MWh)

$(ER)_i$ = Monthly Hg emission rate, for month “i”, (lb/MWh)

n = The number of unit operating hours in month “i” with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in §75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 3 through 5 of this section, except that for a particular pair of sorbent traps, C_h in Equation 3 shall be the flow-proportional average Hg concentration measured over the data collection

period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride (Hg^B or $HgCl_2$) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using $HgCl_2$ standards, as described in section 8.3 of Performance Specification 12-A in appendix B to this part (note: Hg^B standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

10. Newly redesignated §60.51a is amended by:

a. Revising paragraph (a);

b. In paragraph (c) introductory text by revising the existing references from “§60.47a” and “§60.46a(h)” to “§60.49a” and “§60.48a(h),” respectively;

c. In paragraph (d)(1) by revising the existing reference from “§60.46a(d)” to “§60.48a(d)”; and

d. In paragraph (e)(1) by revising the existing reference from “§60.48a” to “§60.50a.”

e. Redesignating paragraphs (g),(h), (i), and (j) as paragraphs (h), (i), (j), and (k), respectively, and adding a new paragraph (g); and

f. Revising the first sentence of newly redesignated paragraph (k).

The revisions and additions read as follows:

§60.51a Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, particulate matter, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

* * * * *

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

* * * * *

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section.

* * * * *

11. Section 60.52a is added to read as follows;

§60.52a Recordkeeping Requirements.

The owner or operator of an affected facility subject to the emissions limitations in §60.45a or §60.46a shall provide notifications in accordance with §60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of §60.7(f).

* * * * *

Subpart GGGG–[ADDED]

12. Part 60 is amended by adding subpart GGGG to read as follows:

Subpart GGGG-[Reserved]

13.

Part 60 is amended by adding subpart HHHH to read as follows:

SUBPART HHHH– EMISSION GUIDELINES AND COMPLIANCE TIMES FOR COAL-FIRED ELECTRIC STEAM GENERATING UNITS

Sec.

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Hg Budget Trading Program General Provisions

§60.4101 Purpose.

This subpart establishes the model rule comprising general provisions and the designated representative, permitting, allowance, and monitoring provisions for the State mercury (Hg) Budget Trading Program, under section 111 of the Clean Air Act (CAA) and §60.24(h)(6) of this chapter, as a means of reducing national Hg emissions. The owner or operator of a unit or a source shall comply with the requirements of this subpart as a matter of Federal law only if the State with jurisdiction over the unit and the source incorporates by reference this subpart or otherwise adopts the requirements of this subpart in accordance with §60.24(h)(6) of this chapter, the State submits to the Administrator one or more revisions of the State plan that include such adoption, and the Administrator approves such revisions. If the State adopts the requirements of this subpart in accordance with §60.24(h)(6) of this chapter, then the State authorizes the Administrator to assist the State in implementing the Hg Budget Trading Program by carrying out the functions set forth for the Administrator in this subpart.

§60.4102 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each Hg Allowance Tracking System account.

Acid Rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator’s duly authorized representative.

Allocate or allocation means the determination by the permitting authority or the Administrator of the amount of Hg allowances to be initially credited to a Hg Budget unit or a new unit set-aside under §§60.4140 through 60.4142.

Allowance transfer deadline means, for a control period, midnight of March 1, if it is a business day, or, if

March 1 is not a business day, midnight of the first business day thereafter immediately following the control period and is the deadline by which a Hg allowance transfer must be submitted for recordation in a Hg Budget source’s compliance account in order to be used to meet the source’s Hg Budget emissions limitation for such control period in accordance with §60.4154.

<u>Alternate Hg designated representative</u> means, for a Hg Budget source and each Hg Budget unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source in accordance with §§60.4110 through 60.4114, to act on behalf of the Hg designated representative in matters pertaining to the Hg Budget Trading Program.

<u>Automated data acquisition and handling system</u> or <u>DAHS</u> means that component of the continuous emission monitoring system (CEMS), or other emissions monitoring system approved for use under §§60.4170 though 60.4176, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required §§60.4170 through 60.4176.

<u>Boiler</u> means an enclosed fossil- or other fuel-fired

combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

CAIR NO_X Annual Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AA through II of part 96 of this chapter and §51.123 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

CAIR NO_X Ozone Season Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAAA through IIII of part 96 of this chapter and §51.123 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

CAIR SO_2 Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through III of part 96 of this chapter and §51.124 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

Clean Air Act or CAA means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90, 91, 95, or 98a (incorporated by reference).

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year.

Cogeneration unit means a stationary, coal-fired boiler or stationary, coal-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any

calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

<u>Combustion turbine</u> means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

<u>Commence commercial operation</u> means, with regard to a unit serving a generator:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in §60.4105.

(i) For a unit that is a Hg Budget unit under §60.4104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit’s date of commencement of commercial operation.

(ii) For a unit that is a Hg Budget unit under §60.4104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in §60.4105, for a unit that is not a Hg Budget unit under §60.4104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition, the unit’s date for commencement of commercial operation shall be the date on which the unit becomes a Hg

Budget unit under §60.4104.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

<u>Commence operation</u> means:

(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber, except as provided in §60.4105.

(i) For a unit that is a Hg Budget unit under §60.4104 on the date the unit commences operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit’s date of commencement of operation.

(ii) For a unit that is a Hg Budget unit under §60.4104 on the date the unit commences operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in §60.4105, for a unit that is not a Hg Budget unit under §60.4104 on the date the unit commences operation as defined in paragraph (1) of this definition, the unit’s date for commencement of operation shall be the date on which the unit becomes a Hg Budget unit under §60.4104.

(i) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit’s date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means a Hg Allowance Tracking System account, established by the Administrator for a Hg Budget source under §§60.4150 through 60.4157, in which any Hg allowance allocations for the Hg Budget units at the source are initially recorded and in which are held any Hg allowances available for use for a control period in order to meet the source’s Hg Budget emissions limitation in accordance with §60.4154.

Continuous emission monitoring system or CEMS means the equipment required under §§60.4170 through 60.4176 to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of Hg emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with part 75 of this chapter. The following systems are the principal types of CEMS required under §§60.4170 through

60.4176:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in units of standard cubic feet per hour (scfh);

(2) A Hg concentration monitoring system, consisting of a Hg pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of Hg emissions in units of micrograms per dry standard cubic meter (:g/dscm);

(3) A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O.

(4) A carbon dioxide monitoring system, consisting of a CO_2 concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An oxygen monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record

of O_2, in percent O_2.

Control period means the period beginning January 1 of a calendar year and ending on December 31 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the Hg designated representative and as determined by the Administrator in accordance with §§60.4170 through 60.4176.

Excess emissions means any ounce of mercury emitted by the Hg Budget units at a Hg Budget source during a control period that exceeds the Hg Budget emissions limitation for the source.

General account means a Hg Allowance Tracking System account, established under §60.4151, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a specified period of time, the product (in MMBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/MMBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the Hg designated representative and determined by the Administrator in accordance with §§60.4170 through 60.4176 and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in MMBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in MMBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Hg authorized account representative means, with regard to a general account, a responsible natural person who is authorized, in accordance with §60.4152, to transfer and otherwise dispose of Hg allowances held in the general account and, with regard to a compliance account, the Hg designated representative of the source.

Hg allowance means a limited authorization issued by the permitting authority or the Administrator under §§60.4140 through 60.4142 to emit one ounce of mercury during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the Hg Budget Trading Program. An authorization to emit mercury that is not issued under the provisions of a State plan that adopt the requirements of this subpart and are approved by the Administrator in accordance with §60.24(h)(6) of this chapter shall not be a “Hg allowance.”

<u>Hg allowance deduction</u> or <u>deduct Hg allowances</u> means the permanent withdrawal of Hg allowances by the Administrator from a compliance account in order to account for a specified number of ounces of total mercury emissions from all Hg Budget units at a Hg Budget source for a control period, determined in accordance with §§60.4150 though 60.4157 and §§60.4170 through 60.4176, or to account for excess emissions.

<u>Hg allowances held</u> or <u>hold Hg allowances</u> means the Hg allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with §§60.4150 through 60.4162, in a Hg Allowance Tracking System account.

<u>Hg Allowance Tracking System</u> means the system by which the Administrator records allocations, deductions, and transfers of Hg allowances under the Hg Budget Trading

Program. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

Hg Allowance Tracking System account means an account in the Hg Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of Hg allowances.

Hg Budget emissions limitation means, for a Hg Budget source, the equivalent in ounces of the Hg allowances available for deduction for the source under §60.4154(a) and (b) for a control period.

Hg Budget permit means the legally binding and Federally enforceable written document, or portion of such document, issued by the permitting authority under §§60.4120 through 60.4124, including any permit revisions, specifying the Hg Budget Trading Program requirements applicable to a Hg Budget source, to each Hg Budget unit at the source, and to the owners and operators and the Hg designated representative of the source and each such unit.

Hg Budget source means a source that includes one or more Hg Budget units.

Hg Budget Trading Program means a multi-state Hg air pollution control and emission reduction program approved and administered by the Administrator in accordance with this subpart and §60.24(h)(6) of this chapter, as a means of reducing national Hg emissions.

Hg Budget unit means a unit that is subject to the Hg Budget Trading Program under §60.4104.

Hg designated representative means, for a Hg Budget source and each Hg Budget unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with §§60.4110 through 60.4114, to represent and legally bind each owner and operator in matters pertaining to the Hg Budget Trading Program.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy from any specified generating unit and pays its proportional amount of such unit’s total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or

release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Lignite means coal that is classified as lignite A or B according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90, 91, 95, or 98a (incorporated by reference).

Maximum design heat input means, starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady-state basis as specified by the manufacturer of the unit, or, starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady-state basis, such decreased maximum amount as specified by the person conducting the physical change.

Monitoring system means any monitoring system that meets the requirements of §§60.4170 through 60.4176, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as specified by the person conducting the physical change.

Operator means any person who operates, controls, or supervises a Hg Budget unit or a Hg Budget source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Ounce means 2.84 x 10^7 micrograms. For the purpose of determining compliance with the Hg Budget emissions limitation, total ounces of mercury emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with §§60.4170 through 60.4176, but with any remaining fraction of an ounce equal to or greater than 0.50 ounces deemed to equal one ounce and any remaining fraction of an ounce less than 0.50 ounces deemed to equal zero ounces.

<u>Owner</u> means any of the following persons:

(1) With regard to a Hg Budget source or a Hg Budget unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a Hg Budget unit at the source ro the Hg Budget unit;

(ii) Any holder of a leasehold interest in a Hg Budget unit at the source or the Hg Budget unit; or

(iii) Any purchaser of power from a Hg Budget unit at the source or the Hg Budget unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such Hg Budget unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the Hg allowances held in the general account and who is subject to the binding agreement for the Hg authorized account representative to represent the person’s ownership interest with respect to Hg allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the Hg Budget Trading Program in accordance with §§60.4120 through 60.4124 or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit’s maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to Hg allowances, the movement of Hg allowances by the Administrator into or between Hg Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;

(2) Integrated gasification combined cycle;

(3) Magnetohydrodynamics;

(4) Direct and indirect coal-fired turbines;

(5) Integrated gasification fuel cells; or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Serial number means, for a Hg allowance, the unique identification number assigned to each Hg allowance by the Administrator.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the CAA, a “source,” including a “source” with multiple units, shall be considered a single “facility.”

State means:

(1) For purposes of referring to a governing entity, one of the States in the United States, the District of Columbia, or, if approved for treatment as a State under part 49 of this chapter, the Navajo Nation or Ute Indian Tribe that adopts the Hg Budget Trading Program pursuant to §60.24(h)(6) of this chapter; or

(2) For purposes of referring to geographic areas, one of the States in the United State, the District of Columbia, the Navajo Nation Indian country, or the Ute Tribe Indian country.

Subbituminous means coal that is classified as subbituminous A, B, or C, according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90, 91, 95, or 98a (incorporated by reference).

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery. Compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the CAA and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the CAA and part 70 or 71 of this chapter.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary coal-fired boiler or a stationary coal-fired combustion turbine.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or hour of unit operation means an hour in which a unit combusts any fuel.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heat application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§60.4103 Measurements, Abbreviations, and Acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu - British thermal unit.

CO_2 - carbon dioxide.

Hg - mercury.

hr - hour.

kW - kilowatt electrical.

kWh - kilowatt hour.

MMBtu - million Btu.

MWe - megawatt electrical.

MWh - megawatt hour.

NO_X - nitrogen oxides.

O_2 - oxygen.

ppm - parts per million.

lb - pound.

scfh - standard cubic feet per hour.

SO_2 - sulfur dioxide.

H_2O - water.

yr - year.

§60.4104 Applicability.

The following units in a State shall be Hg Budget units, and any source that includes one or more such units shall be a Hg Budget source, subject to the requirements of this subpart:

(a) Except as provided in paragraph (b) of this section, a unit serving at any time, since the start-up of the 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 during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, 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 during the 12-month period 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.

§60.4105 Retired Unit Exemption.

(a)(1) Any Hg Budget unit that is permanently retired shall be exempt from the Hg Budget Trading Program, except for the provisions of this section, §60.4102, §60.4103, §60.4104, §60.4106(c)(4) through (8), §60.4107, and §§60.4150 through 60.4162.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the Hg Budget unit is permanently retired. Within 30 days of the unit’s permanent retirement, the Hg designated representative shall submit a statement to the permitting authority otherwise responsible for administering any Hg Budget permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

(3) After receipt of the notice under paragraph (a)(2) of this section, the permitting authority will amend any permit under §§60.4120 through 60.4124 covering the source

at which the unit is located to add the provisions and requirements of the exemption under paragraphs (a)(1) and (b) of this section.

(b) Special provisions.

(1) A unit exempt under paragraph (a) of this section shall not emit any mercury, starting on the date that the exemption takes effect.

(2) The permitting authority will allocate Hg allowances under §§60.4140 through 60.4142 to a unit exempt under paragraph (a) of this section.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(4) The owners and operators and, to the extent applicable, the Hg designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the Hg Budget Trading Program concerning all periods for which the exemption is not in effect, even

if such requirements arise, or must be complied with, after the exemption takes effect.

(5) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the Hg designated representative of the source submits a complete Hg Budget permit application under §60.4122 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the unit resumes operation.

(6) On the earlier of the following dates, a unit exempt under paragraph (a) of this section shall lose its exemption:

(i) The date on which the Hg designated representative submits a Hg Budget permit application for the unit under paragraph (b)(5) of this section;

(ii) The date on which the Hg designated representative is required under paragraph (b)(5) of this section to submit a Hg Budget permit application for the unit; or

(iii) The date on which the unit resumes operation, if the Hg designated representative is not required to submit a Hg Budget permit application for the unit.

(7) For the purpose of applying monitoring, reporting, and recordkeeping requirements under §§60.4170 through 60.4176, a unit that loses its exemption under paragraph (a) of this section shall be treated as a unit that commences operation and commercial operation on the first date on which the unit resumes operation.

<u>§60.4106 Standard Requirements</u>.

(a) Permit Requirements.

(1) The Hg designated representative of each Hg Budget source required to have a title V operating permit and each Hg Budget unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete Hg Budget permit application under §60.4122 in accordance with the deadlines specified in §60.4121(a) and (b); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a Hg Budget permit application and issue or deny a Hg Budget permit.

(2) The owners and operators of each Hg Budget source required to have a title V operating permit and each Hg Budget unit required to have a title V operating permit at the source shall have a Hg Budget permit issued by the permitting authority under §§60.4120 through 60.4124 for the

source and operate the source and the unit in compliance with such Hg Budget permit.

(3) The owners and operators of a Hg Budget source that is not required to have a title V operating permit and each Hg Budget unit that is not required to have a title V operating permit are not required to submit a Hg Budget permit application, and to have a Hg Budget permit, under §§60.4120 through 60.4124 for such Hg Budget source and such Hg Budget unit.

(b) Monitoring, Reporting, and Recordkeeping Requirements.

(1) The owners and operators, and the Hg designated representative, of each Hg Budget source and each Hg Budget unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§60.4170 through 60.4176.

(2) The emissions measurements recorded and reported in accordance with §§60.4170 through 60.4176 shall be used to determine compliance by each Hg Budget source with the Hg Budget emissions limitation under paragraph (c) of this section.

(c) Mercury emission requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each Hg Budget

source and each Hg Budget unit at the source shall hold, in the source’s compliance account, Hg allowances available for compliance deductions for the control period under §60.4154(a) in an amount not less than the ounces of total mercury emissions for the control period from all Hg Budget units at the source, as determined in accordance with §§60.4170 through 60.4176.

(2) A Hg Budget unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of January 1, 2010 or the deadline for meeting the unit’s monitor certification requirements under §60.4170(b)(1) or (2).

(3) A Hg allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the Hg allowance was allocated.

(4) Hg allowances shall be held in, deducted from, or transferred into or among Hg Allowance Tracking System accounts in accordance with §§60.4160 through 60.4162.

(5) A Hg allowance is a limited authorization to emit one ounce of mercury in accordance with the Hg Budget Trading Program. No provision of the Hg Budget Trading Program, the Hg Budget permit application, the Hg Budget permit, or an exemption under §60.4105 and no provision of

law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A Hg allowance does not constitute a property right.

(7) Upon recordation by the Administrator under §§60.4150 through 60.4162, every allocation, transfer, or deduction of a Hg allowance to or from a Hg Budget unit’s compliance account is incorporated automatically in any Hg Budget permit of the source that includes the Hg Budget unit.

(d) Excess emissions requirements.

(1) If a Hg Budget source emits mercury during any control period in excess of the Hg Budget emissions limitation, then:

(i) The owners and operators of the source and each Hg Budget unit at the source shall surrender the Hg allowances required for deduction under §60.4154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(ii) Each ounce of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of the Hg Budget source and each Hg Budget unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under §60.4113 for the Hg designated representative for the source and each Hg Budget unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §60.4113 changing the Hg designated representative.

(ii) All emissions monitoring information, in accordance with §§60.4170 through 60.4176, provided that to the extent that §§60.4170 through 60.4176 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Hg Budget Trading Program.

(iv) Copies of all documents used to complete a Hg Budget permit application and any other submission under the Hg Budget Trading Program or to demonstrate compliance with the requirements of the Hg Budget Trading Program.

(2) The Hg designated representative of a Hg Budget source and each Hg Budget unit at the source shall submit the reports required under the Hg Budget Trading Program, including those under §§60.4170 through 60.4176.

(f) Liability.

(1) Each Hg Budget source and each Hg Budget unit shall meet the requirements of the Hg Budget Trading Program.

(2) Any provision of the Hg Budget Trading Program that applies to a Hg Budget source or the Hg designated representative of a Hg Budget source shall also apply to the owners and operators of such source and of the Hg Budget units at the source.

(3) Any provision of the Hg Budget Trading Program that applies to a Hg Budget unit or the Hg designated representative of a Hg Budget unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the Hg Budget Trading Program, a Hg Budget permit application, a Hg Budget permit, or an exemption under §60.4105 shall be construed as exempting or excluding the owners and operators, and the Hg designated representative, of a Hg Budget source or Hg Budget unit from compliance with any other provision of the applicable, approved State implementation plan, a Federally enforceable permit, or the CAA.

<u>§60.4107 Computation of Time</u>.

(a) Unless otherwise stated, any time period scheduled, under the Hg Budget Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the Hg Budget Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the Hg Budget Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

<u>§60.4108 Appeal Procedures</u>.

The appeal procedures for decisions of the Administrator under the Hg Budget Trading Program shall be the procedures set forth in part 78 of this chapter, applied by replacing the terms “subparts AA through II of part 96 of this chapter,” “§96.141(b)(2) or (c)(2),” “§96.154,” “§96.156,” “§96.161,” “§96.175,” “CAIR NO_X allowances,” “CAIR NO_X Allowance Tracking System account,” “CAIR designated representative,” “CAIR authorized account representative,” and “§96.106” by the terms “subpart HHHH of this part,” “§60.4141 (b)(2) or (c)(2),” “§60.4154,” “§60.4156,” “§60.4161,” “§60.4175,” “Hg allowances,” “Hg Allowance Tracking System Account,” “Hg designated representative,” “Hg authorized account representative,” and “§60.4106.”

Hg Designated Representative for Hg Budget Sources

§60.4110 Authorization and Responsibilities of Hg Designated Representative.

(a) Except as provided under §60.4111, each Hg Budget source, including all Hg Budget units at the source, shall have one and only one Hg designated representative, with regard to all matters under the Hg Budget Trading Program concerning the source or any Hg Budget unit at the source.

(b) The Hg designated representative of the Hg Budget source shall be selected by an agreement binding on the owners and operators of the source and all Hg Budget units at the source and shall act in accordance with the certification statement in §60.4113(a)(5)(iv).

(c) Upon receipt by the Administrator of a complete certificate of representation under §60.4113, the Hg designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the Hg Budget source represented and each Hg Budget unit at the source in all matters pertaining to the Hg Budget Trading Program, notwithstanding any agreement between the Hg designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the Hg designated representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No Hg Budget permit will be issued, no emissions data reports will be accepted, and no Hg Allowance Tracking System account will be established for a Hg Budget unit at a source, until the Administrator has received a complete certificate of representation under §60.4113 for a Hg designated representative of the source and the Hg Budget units at the source.

(e)(1) Each submission under the Hg Budget Trading

Program shall be submitted, signed, and certified by the Hg designated representative for each Hg Budget source on behalf of which the submission is made. Each such submission shall include the following certification statement by the Hg designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a Hg Budget source or a Hg Budget unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§60.4111 Alternate Hg Designated Representative.

(a) A certificate of representation under §60.4113 may designate one and only one alternate Hg designated representative, who may act on behalf of the Hg designated representative. The agreement by which the alternate Hg designated representative is selected shall include a procedure for authorizing the alternate Hg designated representative to act in lieu of the Hg designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation under §60.4113, any representation, action, inaction, or submission by the alternate Hg designated representative shall be deemed to be a representation, action, inaction, or submission by the Hg designated representative.

(c) Except in this section and §§60.4102, 60.4110(a) and (d), 60.4112, 60.4113, 60.4151, and 60.4174, whenever the term “Hg designated representative” is used in this subpart, the term shall be construed to include the Hg designated representative or any alternate Hg designated representative.

§60.4112 Changing Hg Designated Representative and Alternate Hg Designated Representative; Changes in Owners and Operators.

(a) Changing Hg designated representative. The Hg designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §60.4113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous Hg designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new Hg designated representative and the owners and operators of the Hg Budget source and the Hg Budget units at the source.

(b) Changing alternate Hg designated representative. The alternate Hg designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §60.4113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate Hg designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate Hg designated representative and the owners and operators of the Hg Budget source and the Hg Budget units at the source.

(c) Changes in owners and operators.

(1) In the event a new owner or operator of a Hg

Budget source or a Hg Budget unit is not included in the list of owners and operators in the certificate of representation under §60.4113, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the Hg designated representative and any alternate Hg designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a Hg Budget source or a Hg Budget unit, including the addition of a new owner or operator, the Hg designated representative or any alternate Hg designated representative shall submit a revision to the certificate of representation under §60.4113 amending the list of owners and operators to include the change.

<u>§60.4113 Certificate of Representation</u>.

(a) A complete certificate of representation for a Hg designated representative or an alternate Hg designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the Hg Budget source, and each

Hg Budget unit at the source, for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the Hg designated representative and any alternate Hg designated representative.

(3) A list of the owners and operators of the Hg Budget source and of each Hg Budget unit at the source.

(4) The following certification statements by the Hg designated representative and any alternate Hg designated representative:

(i) “I certify that I was selected as the Hg designated representative or alternate Hg designated representative, as applicable, by an agreement binding on the owners and operators of the source and each Hg Budget unit at the source.”

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the Hg Budget Trading Program on behalf of the owners and operators of the source and of each Hg Budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.”

(iii) “I certify that the owners and operators of the source and of each Hg Budget unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.”

(iv) “Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a Hg Budget unit, or where a customer purchases power from a Hg Budget unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘Hg designated representative’ or ‘alternate Hg designated representative,’ as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each Hg Budget unit at the source; and Hg allowances and proceeds of transactions involving Hg allowances will be deemed to be held or distributed in proportion to each holder’s legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of Hg allowances by contract, Hg allowances and proceeds of transactions involving Hg allowances will be deemed to be held or distributed in accordance with the contract.”

(5) The signature of the Hg designated representative and any alternate Hg designated representative and the dates

signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

<u>§60.4114 Objections Concerning Hg Designated Representative</u>.

(a) Once a complete certificate of representation under §60.4113 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §60.4113 is received by the Administrator.

(b) Except as provided in §60.4112(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the Hg designated representative shall affect any representation, action, inaction, or submission of the Hg designated representative or the finality of any decision or order by the permitting authority or the Administrator under the Hg Budget Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any Hg designated representative, including private legal disputes concerning the proceeds of Hg allowance transfers.

Permits

§60.4120 General Hg Budget Trading Program Permit Requirements.

(a) For each Hg Budget source required to have a title V operating permit, such permit shall include a Hg Budget permit administered by the permitting authority for the title V operating permit. The Hg Budget portion of the title V permit shall be administered in accordance with the permitting authority’s title V operating permits regulations promulgated under part 70 or 71 of this chapter, except as provided otherwise by this section and §§60.4121 through 60.4124.

(b) Each Hg Budget permit shall contain, with regard to the Hg Budget source and the Hg Budget units at the source covered by the Hg Budget permit, all applicable Hg Budget Trading Program requirements and shall be a complete and separable portion of the title V operating permit.

§60.4121 Submission of Hg Budget Permit Applications.

(a) Duty to apply. The Hg designated representative of any Hg Budget source required to have a title V operating permit shall submit to the permitting authority a complete Hg Budget permit application under §60.4122 for the source covering each Hg Budget unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the Hg Budget unit commences operation.

(b) Duty to Reapply. For a Hg Budget source required to have a title V operating permit, the Hg designated representative shall submit a complete Hg Budget permit application under §60.4122 for the source covering each Hg Budget unit at the source to renew the Hg Budget permit in accordance with the permitting authority’s title V operating permits regulations addressing permit renewal.

§60.4122 Information Requirements for Hg Budget Permit Applications.

A complete Hg Budget permit application shall include the following elements concerning the Hg Budget source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the Hg Budget source;

(b) Identification of each Hg Budget unit at the Hg

Budget source; and

(c) The standard requirements under §60.4106.

§60.4123 Hg Budget Permit Contents and Term.

(a) Each Hg Budget permit will contain, in a format prescribed by the permitting authority, all elements required for a complete Hg Budget permit application under §60.4122.

(b) Each Hg Budget permit is deemed to incorporate automatically the definitions of terms under §60.4102 and, upon recordation by the Administrator under §§60.4150 through 60.4162, every allocation, transfer, or deduction of a Hg allowance to or from the compliance account of the Hg Budget source covered by the permit.

(c) The term of the Hg Budget permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the Hg Budget permit with issuance, revision, or renewal of the Hg Budget source's title V operating permit.

§60.4124 Hg Budget Permit Revisions.

Except as provided in §60.4123(b), the permitting authority will revise the Hg Budget permit, as necessary, in accordance with the permitting authority's title V operating permits regulations addressing permit revisions.

§60.4130 [Reserved]

§60.4124 Hg Budget Permit Revisions.

Except as provided in §60.4123(b), the permitting authority will revise the Hg Budget permit, as necessary, in accordance with the permitting authority’s title V operating permits regulations addressing permit revisions.

§60.4130 [Reserved]

Hg Allowance Allocations

§60.4140 State Trading Budgets.

The State trading budgets for annual allocations of Hg allowances for the control periods in 2010 through 2017 and in 2018 and thereafter are respectively as follows:

State	**State Trading 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 Indian country	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	2.057	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 Indian country	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

§60.4141 Timing Requirements for Hg Allowance Allocations.

(a) By October 31, 2006, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with §60.4142(a) and (b), for the control periods in 2010, 2011, 2012, 2013, and 2014.

(b)(1) By October 31, 2008 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with §60.4142(a) and (b), for the control period in the sixth year after the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the Hg allowance allocations in accordance with paragraph (b)(1) of this section, the Administrator will assume that the allocations of Hg allowances for the applicable control period are the same as for the control period that immediately precedes the applicable control period, except that, if the applicable control period is in 2018, the Administrator will assume that the allocations equal the allocations for the control period in 2017, multiplied by the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140 for 2018 and thereafter and divided by such amount of ounces of Hg emissions for 2010 through 2017.

(c)(1) By October 31, 2010 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with §60.4142(a), (c), and (d), for the control period in the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the Hg allowance allocations in accordance with paragraph (c)(1) of this section, the Administrator will assume that the allocations of Hg allowances for the applicable control period are the same as for the control period that immediately precedes the applicable control period, except that, if the applicable control period is in 2018, the Administrator will assume that the allocations equal the allocations for the control period in 2017, multiplied by the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140 for 2018 and thereafter and divided by such amount of ounces of Hg emissions for 2010 through 2017 and except that any Hg Budget unit that would otherwise be allocated Hg allowances under §60.4142(a) and (b), as well as under §60.4142(a), (c), and (d), for the applicable control period will be assumed to be allocated no Hg allowances under §60.4142(a), (c), and (d) for the applicable control period.

§60.4142 Hg Allowance Allocations.

(a)(1) The baseline heat input (in MMBtu) used with respect to Hg allowance allocations under paragraph (b) of this section for each Hg Budget unit will be:

(i) For units commencing operation before January 1, 2001, the average of the three highest amounts of the unit’s adjusted control period heat input for 2000 through 2004, with the adjusted control period heat input for each year calculated as the sum of the following:

(A) Any portion of the unit’s control period heat input for the year that results from the unit’s combustion of lignite, multiplied by 3.0;

(B) Any portion of the unit’s control period heat input for the year that results from the unit’s combustion of subbituminous coal, multiplied by 1.25; and

(C) Any portion of the unit’s control period heat input for the year that is not covered by paragraph (a)(1)(i)(A) or (B) of this section, multiplied by 1.0.

(ii) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 or more consecutive calendar years, the average of the 3 highest amounts of the unit’s total converted control period heat input over the first such 5 years.

(2)(i) A unit’s control period heat input for a calendar year under paragraphs (a)(1)(i) of this section, and a unit’s total ounces of Hg emissions during a calendar year under paragraph (c)(3) of this section, will be determined in accordance with part 75 of this chapter, to the extent the unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the permitting authority for the unit, to the extent the unit was not otherwise subject to the requirements of part 75 of this chapter for the year. The unit's types and amounts of fuel combusted, under paragraph (a)(1)(i) of this section, will be based on the best available data reported to the permitting authority for the unit.

(ii) A unit's converted control period heat input for a calendar year specified under paragraph (a)(1)(ii) of this section equals:

(A) Except as provided in paragraph (a)(2)(ii)(B) or (C) of this section, the control period gross electrical output of the generator or generators served by the unit multiplied by 7,900 Btu/kWh and divided by 1,000,000 Btu/MMBtu, provided that if a generator is served by 2 or more units, then the gross electrical output of the generator will be attributed to each unit in proportion to the unit's share of the total control period heat input of such units for the year;

(B) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the total heat energy (in Btu) of the steam produced by the boiler during the control period, divided by 0.8 and by 1,000,000 Btu/MMBtu; or

(C) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the control period gross electrical output of the enclosed device comprising the compressor, combustor, and turbine multiplied by 3,413 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period multiplied by 0.8, and with the sum divided by 1,000,000 Btu/MMBtu.

(b)(1) For each control period in 2010 and thereafter, the permitting authority will allocate to all Hg Budget units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of Hg allowances equal to 95 percent for a control period in 2010 through 2014, and 97 percent for a control period in 2015 and thereafter, of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140 (except as provided in paragraph (d) of this section).

(2) The permitting authority will allocate Hg

allowances to each Hg Budget unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of Hg allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such Hg Budget unit to the total amount of baseline heat input of all such Hg Budget units in the State and rounding to the nearest whole allowance as appropriate.

(c) For each control period in 2010 and thereafter, the permitting authority will allocate Hg allowances to Hg Budget units in the State that commenced operation on or after January 1, 2001 and do not yet have a baseline heat input (as determined under paragraph (a) of this section), in accordance with the following procedures:

(1) The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated Hg allowances equal to 5 percent for a control period in 2010 through 2014, and 3 percent for a control period in 2015 and thereafter, of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140.

(2) The Hg designated representative of such a Hg Budget unit may submit to the permitting authority a request, in a format specified by the permitting authority,

to be allocated Hg allowances, starting with the later of the control period in 2010 or the first control period after the control period in which the Hg Budget unit commences commercial operation and until the first control period for which the unit is allocated Hg allowances under paragraph (b) of this section. The Hg allowance allocation request must be submitted on or before July 1 of the first control period for which the Hg allowances are requested and after the date on which the Hg Budget unit commences commercial operation.

(3) In a Hg allowance allocation request under paragraph (c)(2) of this section, the Hg designated representative may request for a control period Hg allowances in an amount not exceeding the Hg Budget unit’s total ounces of Hg emissions during the control period immediately before such control period.

(4) The permitting authority will review each Hg allowance allocation request under paragraph (c)(2) of this section and will allocate Hg allowances for each control period pursuant to such request as follows:

(i) The permitting authority will accept an allowance allocation request only if the request meets, or is adjusted by the permitting authority as necessary to meet, the requirements of paragraphs (c)(2) and (3) of this section.

(ii) On or after July 1 of the control period, the permitting authority will determine the sum of the Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section) in all allowance allocation requests accepted under paragraph (c)(4)(i) of this section for the control period.

(iii) If the amount of Hg allowances in the new unit set-aside for the control period is greater than or equal to the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate the amount of Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each Hg Budget unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of Hg allowances in the new unit set-aside for the control period is less than the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate to each Hg Budget unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of Hg allowances in the new unit set-aside for the control period, divided by the sum determined under paragraph (c)(4)(ii) of this section, and rounded to the nearest whole allowance as appropriate.

(v) The permitting authority will notify each Hg designated representative that submitted an allowance allocation request of the amount of Hg allowances (if any) allocated for the control period to the Hg Budget unit covered by the request.

(d) If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated Hg allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each Hg Budget unit that was allocated Hg allowances under paragraph (b) of this section an amount of Hg allowances equal to the total amount of such remaining unallocated Hg allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 95 percent for 2010 through 2014, and 97 percent for 2014 and thereafter, of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140, and rounded to the nearest whole allowance as appropriate.

Hg Allowance Tracking System

§60.4150 [Reserved].

§60.4151 Establishment of Accounts.

(a) Compliance accounts. Upon receipt of a complete certificate of representation under §60.4113, the Administrator will establish a compliance account for the Hg Budget source for which the certificate of representation was submitted unless the source already has a compliance account.

(b) General accounts.

(1) Application for general account.

(i) Any person may apply to open a general account for the purpose of holding and transferring Hg allowances. An application for a general account may designate one and only one Hg authorized account representative and one and only one alternate Hg authorized account representative who may act on behalf of the Hg authorized account representative. The agreement by which the alternate Hg authorized account representative is selected shall include a procedure for authorizing the alternate Hg authorized account representative to act in lieu of the Hg authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the Hg authorized account representative and any alternate Hg authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the Hg authorized account representative and any alternate Hg authorized account representative to represent their ownership interest with respect to the allowances held in the general account;

(D) The following certification statement by the Hg authorized account representative and any alternate Hg authorized account representative: “I certify that I was selected as the Hg authorized account representative or the alternate Hg authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the Hg Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.”

(E) The signature of the Hg authorized account representative and any alternate Hg authorized account representative and the dates signed.

(iii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of Hg authorized account representative.

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The Hg authorized account representative and any alternate Hg authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to Hg allowances held in the general account in all matters pertaining to the Hg Budget Trading Program, notwithstanding any agreement between the Hg authorized account representative or any alternate Hg authorized account representative and such person. Any such person shall be bound by any order or decision issued to the Hg authorized account representative or any alternate Hg authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate Hg authorized account representative shall be deemed to be a representation, action, inaction, or submission by the Hg authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the Hg authorized account representative or any alternate Hg authorized account representative for the persons having an ownership interest with respect to Hg allowances held in the general account. Each such submission shall include the following certification statement by the Hg authorized account representative or any alternate Hg authorized account representative: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the Hg allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(iii) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) Changing Hg authorized account representative and alternate Hg authorized account representative; changes in persons with ownership interest.

(i) The Hg authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous Hg authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new Hg authorized account representative and the persons with an ownership interest with respect to the Hg allowances in the general account.

(ii) The alternate Hg authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate Hg authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate Hg authorized account representative and the persons with an ownership interest with respect to the Hg allowances in the general account.

(iii)(A) In the event a new person having an ownership interest with respect to Hg allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the Hg authorized account representative and any alternate Hg authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to Hg allowances in the general account, including the addition of persons, the Hg authorized account representative or any alternate Hg authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the Hg allowances in the general account to include the change.

(4) Objections concerning Hg authorized account representative.

(i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the Hg authorized account representative or any alternative

Hg authorized account representative for a general account shall affect any representation, action, inaction, or submission of the Hg authorized account representative or any alternative Hg authorized account representative or the finality of any decision or order by the Administrator under the Hg Budget Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the Hg authorized account representative or any alternative Hg authorized account representative for a general account, including private legal disputes concerning the proceeds of Hg allowance transfers.

(c) Account identification. The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§60.4152 Responsibilities of Hg Authorized Account Representative.

Following the establishment of a Hg Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of Hg allowances in the account, shall be made only by the Hg authorized account representative for the account.

§60.4153 Recordation of Hg Allowance Allocations.

(a) By December 1, 2006, the Administrator will record in the Hg Budget source’s compliance account the Hg allowances allocated for the Hg Budget units at a source, as submitted by the permitting authority in accordance with §60.4141(a), for the control periods in 2010, 2011, 2012, 2013, and 2014.

(b) By December 1, 2008, the Administrator will record in the Hg Budget source’s compliance account the Hg allowances allocated for the Hg Budget units at the source, as submitted by the permitting authority or as determined by the Administrator in accordance with §60.4141(b), for the control period in 2015.

(c) In 2011 and each year thereafter, after the Administrator has made all deductions (if any) from a Hg Budget source’s compliance account under §60.4154, the Administrator will record in the Hg Budget source’s compliance account the Hg allowances allocated for the Hg Budget units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with §60.4141(b), for the control period in the sixth year after the year of the control period for which such deductions were or could have been made.

(d) By December 1, 2010 and December 1 of each year thereafter, the Administrator will record in the Hg Budget source’s compliance account the Hg allowances allocated for the Hg Budget units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with §60.4141(c), for the control period in the year of the applicable deadline for recordation under this paragraph.

(e) Serial numbers for allocated Hg allowances. When recording the allocation of Hg allowances for a Hg Budget unit in a compliance account, the Administrator will assign each Hg allowance a unique identification number that will include digits identifying the year of the control period for which the Hg allowance is allocated.

§60.4154 Compliance with Hg Budget Emissions Limitation.

(a) Allowance transfer deadline. The Hg allowances are available to be deducted for compliance with a source’s Hg Budget emissions limitation for a control period in a given calendar year only if the Hg allowances:

(1) Were allocated for the control period in the year or a prior year;

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a Hg allowance transfer correctly submitted for recordation under

§§60.4160 through 60.4162 by the allowance transfer deadline for the control period; and

(3) Are not necessary for deductions for excess emissions for a prior control period under paragraph (d) of this section.

(b) Deductions for compliance. Following the recordation, in accordance with §§60.4160 through 60.4162, of Hg allowance transfers submitted for recordation in a source’s compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account Hg allowances available under paragraph (a) of this section in order to determine whether the source meets the Hg Budget emissions limitation for the control period, as follows:

(1) Until the amount of Hg allowances deducted equals the number of ounces of total Hg emissions, determined in accordance with §§60.4170 through 60.4176, from all Hg Budget units at the source for the control period; or

(2) If there are insufficient Hg allowances to complete the deductions in paragraph (b)(1) of this section, until no more Hg allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) Identification of Hg allowances by serial number. The Hg authorized account representative for a source’s compliance account may request that specific Hg allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the Hg Budget source and the appropriate serial numbers.

(2) First-in, first-out. The Administrator will deduct Hg allowances under paragraph (b) or (d) of this section from the source’s compliance account, in the absence of an identification or in the case of a partial identification of Hg allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any Hg allowances that were allocated to the units at the source, in the order of recordation; and then

(ii) Any Hg allowances that were allocated to any unit and transferred and recorded in the compliance account pursuant to §§60.4160 through 60.4162, in the order of recordation.

(d) Deductions for excess emissions.

(1) After making the deductions for compliance under

paragraph (b) of this section for a control period in a calendar year in which the Hg Budget source has excess emissions, the Administrator will deduct from the source’s compliance account an amount of Hg allowances, allocated for the control period in the immediately following calendar year, equal to 3 times the number of ounces of the source’s excess emissions.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the Hg Budget source or the Hg Budget units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the Clean Air Act or applicable State law.

(e) Recordation of deductions. The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) or (d) of this section.

(f) Administrator’s action on submissions.

(1) The Administrator may review and conduct independent audits concerning any submission under the Hg Budget Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct Hg allowances from or

transfer Hg allowances to a source's compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section.

§60.4155 Banking.

(a) Hg allowances may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any Hg allowance that is held in a compliance account or a general account will remain in such account unless and until the Hg allowance is deducted or transferred under §60.4154, §60.4156, or §§60.4160 through 60.4162..

§60.4156 Account Error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Hg Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the Hg authorized account representative for the account.

§60.4157 Closing of General Accounts.

(a) The Hg authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under §60.4160 through 60.4162 for any Hg allowances in the account to one or more other Hg Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any Hg allowances, the Administrator may notify the Hg authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of Hg allowances into the account under §60.4160 through 60.4162 or a statement submitted by the Hg authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Hg Allowance Transfers

§60.4160 Submission of Hg Allowance Transfers.

An Hg authorized account representative seeking recordation of a Hg allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the Hg allowance transfer shall include the following elements, in a format specified by the Administrator:

(a) The account numbers for both the transferor and transferee accounts;

(b) The serial number of each Hg allowance that is in the transferor account and is to be transferred; and

(c) The name and signature of the Hg authorized account representative of the transferor account and the date signed.

<u>§60.4161 EPA Recordation</u>.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a Hg allowance transfer, the Administrator will record a Hg allowance transfer by moving each Hg allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under §60.4160; and

(2) The transferor account includes each Hg allowance identified by serial number in the transfer.

(b) A Hg allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any Hg allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under §60.4154 for the control period immediately before such allowance transfer deadline.

(c) Where a Hg allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§60.4162 Notification.

(a) Notification of recordation. Within 5 business days of recordation of a Hg allowance transfer under §60.4161, the Administrator will notify the Hg authorized account representatives of both the transferor and transferee accounts.

(b) Notification of non-recordation. Within 10 business days of receipt of a Hg allowance transfer that fails to meet the requirements of §60.4161(a), the Administrator will notify the Hg authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a Hg allowance transfer for recordation following notification of non-recordation.

Monitoring and Reporting

§60.4170 General Requirements.

The owners and operators, and to the extent applicable, the Hg designated representative, of a Hg Budget unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this section, §§60.4171 through

60.4176, and subpart I of part 75 of this chapter. For purposes of complying with such requirements, the definitions in §60.4102 and in §72.2 of this chapter shall apply, and the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “Hg Budget unit,” “Hg designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively, as defined in §60.4102. The owner or operator of a unit that is not a Hg Budget unit but that is monitored under §75.82(b)(2)(i) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a Hg Budget unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each Hg Budget unit shall:

(1) Install all monitoring systems required under this section and §§60.4171 through 60.4176 for monitoring Hg mass emissions and individual unit heat input (including all systems required to monitor Hg concentration, stack gas moisture content, stack gas flow rate, and CO_2 or O_2 concentration, as applicable, in accordance with §§75.81 and 75.82 of this chapter);

(2) Successfully complete all certification tests

required under §60.4171 and meet all other requirements of this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) Compliance deadlines. The owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a Hg Budget unit that commences commercial operation before July 1, 2008, by January 1, 2009.

(2) For the owner or operator of a Hg Budget unit that commences commercial operation on or after July 1, 2008, by the later of the following dates:

(i) January 1, 2009; or

(ii) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a Hg Budget unit for which construction of a new stack or flue or installation of add-on Hg emission controls, a flue gas desulfurization system, a selective catalytic reduction system, or a compact hybrid particulate collector system is completed after the applicable deadline under paragraph (b)(1)or (2) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue, add-on Hg emissions controls, flue gas desulfurization system, selective catalytic reduction system, or compact hybrid particulate collector system.

(c) Reporting data.

(1) Except as provided in paragraph (c)(2) of this section, the owner or operator of a Hg Budget unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for Hg concentration, stack gas flow rate, stack gas moisture content, and any other parameters required to determine Hg mass emissions and heat input in accordance with §75.80(g) of this chapter.

(2) The owner or operator of a Hg Budget unit that does not meet the applicable compliance date set forth in paragraph (b)(3) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in subpart D of part 75 of this chapter, in lieu of the maximum potential (or, as appropriate, minimum potential) values, for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under paragraph (b)(3) of this section.

(d) Prohibitions.

(1) No owner or operator of a Hg Budget unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this section and §§60.4171 through 60.4176 without having obtained prior written approval in accordance with §60.4175.

(2) No owner or operator of a Hg Budget unit shall operate the unit so as to discharge, or allow to be discharged, Hg emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter.

(3) No owner or operator of a Hg Budget unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording Hg mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter.

(4) No owner or operator of a Hg Budget unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under §60.4105 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The Hg designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with §60.4171(c)(3)(i).

<u>§60.4171 Initial Certification and Recertification Procedures</u>.

(a) The owner or operator of a Hg Budget unit shall be exempt from the initial certification requirements of this section for a monitoring system under §60.4170(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendix B to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §60.4170(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) Except as provided in paragraph (a) of this section, the owner or operator of a Hg Budget unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (e.g., a continuous emission monitoring system and an excepted monitoring system (sorbent trap monitoring system) under §75.15) under §60.4170(a)(1). The owner or operator of a unit that qualifies to use the Hg low mass emissions excepted monitoring methodology under §75.81(b) of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (d) or (e) of this section respectively.

(1) Requirements for initial certification. The owner or operator shall ensure that each monitoring system under §60.4170(a)(1)(including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §60.4170(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or

change in any certified continuous emission monitoring system, or an excepted monitoring system (sorbent trap monitoring system) under §75.15, under §60.4170(a)(1) that may significantly affect the ability of the system to accurately measure or record Hg mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with §75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system, and each excepted monitoring system (sorbent trap monitoring system) under §75.15, whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site.

(3) Approval process for initial certification and

recertification. Paragraphs (c)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under §60.4170(a)(1). For recertifications, replace the words “certification” and “initial certification” with the word “recertification,” replace the word “certified” with the word “recertified,” and follow the procedures in §75.20(b)(5) of this chapter in lieu of the procedures in paragraph (c)(3)(v) of this section.

(i) Notification of certification. The Hg designated representative shall submit to the permitting authority, the appropriate EPA Regional Office, and the Administrator written notice of the dates of certification testing, in accordance with §60.4173.

(ii) Certification application. The Hg designated representative shall submit to the permitting authority a certification application for each monitoring system. A complete certification application shall include the information specified in §75.63 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the Hg Budget Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system under paragraph (c)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the permitting authority.

(iv) Certification application approval process. The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (c)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the Hg Budget Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the Hg designated representative must submit the additional information required to complete the certification application. If the Hg designated representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (c)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (c)(3)(iv)(B) of this section is met, then the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (c)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) Audit decertification. The permitting authority may issue a notice of disapproval of the certification status of a monitor in accordance with §60.4172(b).

(v) Procedures for loss of certification. If the permitting authority issues a notice of disapproval of a certification application under paragraph (c)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (c)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), §75.20(b)(5), or §75.21(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) of this chapter:

(*1*) For a disapproved Hg pollutant concentration monitors and disapproved flow monitor, respectively, the maximum potential concentration of Hg and the maximum potential flow rate, as defined in sections 2.1.7.1 and 2.1.4.1 of appendix A to part 75 of this chapter; and

(*2*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.3.1, and 2.1.3.2, and 2.1.5 of appendix A to part 75 of this chapter.

(*3*) For a disapproved excepted monitoring system (sorbent trap monitoring system) under §75.15 and disapproved flow monitor, respectively, the maximum potential concentration of Hg and maximum potential flow rate, as defined in sections 2.1.7.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(B) The Hg designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (c)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the permitting authority’s notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(d) Initial certification and recertification procedures for units using the Hg low mass emission excepted methodology under §75.81(b) of this chapter. The owner or operator of a unit qualified to use the Hg low mass emissions (HgLME) excepted methodology under §75.81(b) of this chapter shall meet the applicable certification and recertification requirements in §75.81(c) through (f) of this chapter.

(e) Certification/recertification procedures for alternative monitoring systems. The Hg designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of §75.20(f) of this chapter.

§60.4172 Out of Control Periods.

(a) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D of part 75 of this chapter.

(b) Audit decertification. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under §60.4171 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in §60.4171 for each disapproved monitoring system.

§60.4173 Notifications.

The Hg designated representative for a Hg Budget unit shall submit written notice to the permitting authority and the Administrator in accordance with §75.61 of this chapter, except that if the unit is not subject to an Acid Rain emissions limitation, the notification is only required to be sent to the permitting authority.

§60.4174 Recordkeeping and Reporting.

(a) General provisions.

(1) The Hg designated representative shall comply with all recordkeeping and reporting requirements in this section and the requirements of §60.4110(e)(1).

(2) If a Hg Budget unit is subject to an Acid Rain emission limitation or the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, or CAIR NO_X Ozone Season Trading Program, and the Hg designated representative who signed and certified any submission that is made under subpart F or G of part 75 of this chapter and that includes data and information required under this section, §§60.4170 through 60.4173, §60.4175, §60.4176, or subpart I of part 75 of this

chapter is not the same person as the designated representative or alternative designated representative, or the CAIR designated representative or alternate CAIR designated representative, for the unit under part 72 of this chapter and the CAIR NO_x Annual Trading Program, CAIR SO_2 Trading Program, or CAIR NO_x Ozone Season Trading Program, then the submission must also be signed by the designated representative or alternative designated representative, or the CAIR designated representative or alternate CAIR designated representative, as applicable.

(b) Monitoring Plans. The owner or operator of a Hg Budget unit shall comply with requirements of §75.84(e) of this chapter.

(c) Certification Applications. The Hg designated representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under §60.4171, including the information required under §75.63 of this chapter.

(d) Quarterly reports. The Hg designated representative shall submit quarterly reports, as follows:

(1) The Hg designated representative shall report the Hg mass emissions data and heat input data for the Hg Budget unit, in an electronic quarterly report in a format

prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2008, the calendar quarter covering January 1, 2009 through March 31, 2009; or

(ii) For a unit that commences commercial operation on or after July 1, 2008, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §60.4170(b), unless that quarter is the third or fourth quarter of 2008, in which case reporting shall commence in the quarter covering January 1, 2009 through March 31, 2009.

(2) The Hg designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.84(f) of this chapter.

(3) For Hg Budget units that are also subject to an Acid Rain emissions limitation or the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, or CAIR NO_X Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the Hg mass emission data, heat input data, and

other information required by this section, §§60.4170 through 60.4173, §60.4175, and §60.4176.

(e) Compliance certification. The Hg designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit’s emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this section, §§60.4170 through 60.4173, §60.4175, §60.4176, and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on Hg emission controls, a flue gas desulfurization system, a selective catalytic reduction system, or a compact hybrid particulate collector system and for all hours where Hg data are substituted in accordance with §75.34(a)(1) of this chapter, the Hg add-on emission controls, flue gas desulfurization system, selective catalytic reduction system, or compact hybrid particulate collector system were operating within the range of parameters listed in the quality assurance/quality

control program under appendix B to part 75 of this chapter, or quality-assured SO_2 emission data recorded in accordance with part 75 of this chapter document that the flue gas desulfurization system, or quality-assured NO_X emission data recorded in accordance with part 75 of this chapter document that the selective catalytic reduction system, was operating properly, as applicable, and the substitute data values do not systematically underestimate Hg emissions.

§60.4175 Petitions.

The Hg designated representative of a Hg unit may submit a petition under §75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of §§60.4170 through 60.4174 and §60.4176. Application of an alternative to any requirement of §§60.4170 through 60.4174 and §60.4176 is in accordance with this section and §§60.4170 through 60.4174 and §60.4176 only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

§60.4176 Additional Requirements to Provide Heat Input Data.

The owner or operator of a Hg Budget unit that monitors and reports Hg mass emissions using a Hg concentration monitoring system and a flow monitoring system shall also monitor and report heat input rate at the unit level using the procedures set forth in part 75 of this chapter.

14. Appendix B to part 60 is amended by adding in numerical order new Performance Specification 12A to read as follows:

PERFORMANCE SPECIFICATION 12A - SPECIFICATIONS AND TEST PROCEDURES FOR TOTAL VAPOR PHASE MERCURY CONTINUOUS EMISSION MONITORING SYSTEMS IN STATIONARY SOURCES

1.0 Scope and Application.

1.1 Analyte.

Analyte	CAS No.
Mercury (Hg)	7439-97-6

1.2 Applicability.

1.2.1 This specification is for evaluating the acceptability of total vapor phase Hg continuous emission monitoring systems (CEMS) installed on the exit gases from fossil fuel fired boilers at the time of or soon after installation and whenever specified in the regulations. The Hg CEMS must be capable of measuring the total concentration in :g/m^3 (regardless of speciation) of vapor phase Hg, and recording that concentration on a wet or dry basis. Particle bound Hg is not included in the measurements.

This specification is not designed to evaluate an installed CEMS’s performance over an extended period of time nor does it identify specific calibration techniques and auxiliary procedures to assess the CEMS’s performance. The source owner or operator, however, is responsible to calibrate, maintain, and operate the CEMS properly. The Administrator may require, under Clean Air Act (CAA) section 114, the operator to conduct CEMS performance evaluations at other times besides the initial test to evaluate the CEMS performance. See §60.13(c).

1.2.2 For an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may conduct the performance evaluation of the Hg CEMS according to §75.20(c)(1) of this chapter and section 6 of appendix A to part 75 of this chapter, in lieu of following the procedures in this performance specification.

2.0 Summary of Performance Specification.

Procedures for measuring CEMS relative accuracy, measurement error and drift are outlined. CEMS installation and measurement location specifications, and data reduction procedures are included. Conformance of the CEMS with the Performance Specification is determined.

3.0 Definitions.

3.1 Continuous Emission Monitoring System (CEMS) means the total equipment required for the determination of a pollutant concentration. The system consists of the following major subsystems:

3.2 Sample Interface means that portion of the CEMS used for one or more of the following: sample acquisition, sample transport, sample conditioning, and protection of the monitor from the effects of the stack effluent.

3.3 Hg Analyzer means that portion of the Hg CEMS that measures the total vapor phase Hg mass concentration and generates a proportional output.

3.4 Data Recorder means that portion of the CEMS that provides a permanent electronic record of the analyzer output. The data recorder may provide automatic data reduction and CEMS control capabilities.

3.5 Span Value means the upper limit of the intended Hg concentration measurement range. The span value is a value equal to two times the emission standard. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the Hg span value(s) may be determined according to section 2.1.7 of appendix A to part 75 of this chapter.

3.6 Measurement Error (ME) means the absolute value of the difference between the concentration indicated by the Hg analyzer and the known concentration generated by a reference gas, expressed as a percentage of the span value, when the entire CEMS, including the sampling interface, is challenged. An ME test procedure is performed to document the accuracy and linearity of the Hg CEMS at several points over the measurement range.

3.7 Upscale Drift (UD) means the absolute value of the difference between the CEMS output response and an upscale Hg reference gas, expressed as a percentage of the span value, when the entire CEMS, including the sampling interface, is challenged after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.8 Zero Drift (ZD) means the absolute value of the difference between the CEMS output response and a zero-level Hg reference gas, expressed as a percentage of the span value, when the entire CEMS, including the sampling interface, is challenged after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.9 Relative Accuracy (RA) means the absolute mean difference between the pollutant concentration(s) determined by the CEMS and the value determined by the reference method (RM) plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the RM tests.

Alternatively, for low concentration sources, the RA may be expressed as the absolute value of the difference between the mean CEMS and RM values.

4.0 Interferences. [Reserved]

5.0 Safety.

The procedures required under this performance specification may involve hazardous materials, operations, and equipment. This performance specification may not address all of the safety problems associated with these procedures. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performing these procedures. The CEMS user's manual and materials recommended by the RM should be consulted for specific precautions to be taken.

6.0 Equipment and Supplies.

6.1 CEMS Equipment Specifications.

6.1.1 Data Recorder Scale. The Hg CEMS data recorder output range must include zero and a high level value. The high level value must be approximately two times the Hg concentration corresponding to the emission standard level for the stack gas under the circumstances existing as the stack gas is sampled. A lower high level value may be used, provided that the measured values do not exceed 95 percent of the high level value. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may set the full-scale range(s) of the Hg analyzer according to section 2.1.7 of appendix A to part 75 of this chapter.

6.1.2 The CEMS design should also provide for the determination of calibration drift at a zero value (zero to 20 percent of the span value) and at an upscale value (between 50 and 100 percent of the high-level value).

6.2 Reference Gas Delivery System. The reference gas delivery system must be designed so that the flowrate of reference gas introduced to the CEMS is the same at all three challenge levels specified in Section 7.1 and at all times exceeds the flow requirements of the CEMS.

6.3 Other equipment and supplies, as needed by the applicable reference method used. See Section 8.6.2.

7.0 Reagents and Standards.

7.1 Reference Gases. Reference gas standards are required for both elemental and oxidized Hg (Hg^{B} and mercuric chloride, $HgCl_2$). The use of National Institute of Standards and Technology (NIST)-certified or NIST-traceable standards and reagents is required. The following gas concentrations are required.

7.1.1 Zero-level. 0 to 20 percent of the span value.

7.1.2 Mid-level. 50 to 60 percent of the span value.

7.1.3 High-level. 80 to 100 percent of the span value.

7.2 Reference gas standards may also be required for the reference methods. See Section 8.6.2.

8.0 Performance Specification (PS) Test Procedure.

8.1 Installation and Measurement Location Specifications.

8.1.1 CEMS Installation. Install the CEMS at an accessible location downstream of all pollution control equipment. Since the Hg CEMS sample system normally extracts gas from a single point in the stack, use a location that has been shown to be free of stratification for SO_2 and NO_x through concentration measurement traverses for those gases. If the cause of failure to meet the RA test requirement is determined to be the measurement location and a satisfactory correction technique cannot be established, the Administrator may require the CEMS to be relocated.

Measurement locations and points or paths that are most likely to provide data that will meet the RA requirements are listed below.

8.1.2 Measurement Location. The measurement location should be (1) at least two equivalent diameters downstream of the nearest control device, point of pollutant generation or other point at which a change of pollutant concentration may occur, and (2) at least half an equivalent diameter upstream from the effluent exhaust. The equivalent duct diameter is calculated as per 40 CFR part 60, appendix A, Method 1.

8.1.3 Hg CEMS Sample Extraction Point. Use a sample extraction point (1) no less than 1.0 meter from the stack or duct wall, or (2) within the centroidal velocity traverse area of the stack or duct cross section.

8.2 RM Measurement Location and Traverse Points. Refer to PS 2 of this appendix. The RM and CEMS locations need not be immediately adjacent.

8.3 ME Test Procedure. The Hg CEMS must be constructed to permit the introduction of known concentrations of Hg^{B} and $HgCl_2$ separately into the sampling system of the CEMS immediately preceding the sample extraction filtration system such that the entire CEMS can be challenged. Sequentially inject each of the three reference gases (zero, mid-level, and high level) for each Hg species. Record the CEMS response and subtract the reference value from the CEMS value, and express the absolute value of the difference as a percentage of the span value (see example data sheet in Figure 12A-1). For each reference gas, the absolute value of the difference between the CEMS response and the reference value shall not exceed 5 percent of the span value. If this specification is not met, identify and correct the problem before proceeding.

8.4 UD Test Procedure.

8.4.1 UD Test Period. While the affected facility is operating at more than 50 percent of normal load, or as specified in an applicable subpart, determine the magnitude of the UD once each day (at 24-hour intervals, to the extent practicable) for 7 consecutive unit operating days according to the procedure given in Sections 8.4.2 through 8.4.3. The 7 consecutive unit operating days need not be 7 consecutive calendar days. Use either Hg^B or $HgCl_2$ standards for this test.

8.4.2 The purpose of the UD measurement is to verify the ability of the CEMS to conform to the established CEMS response used for determining emission concentrations or emission rates. Therefore, if periodic automatic or manual adjustments are made to the CEMS zero and response settings, conduct the UD test immediately before these adjustments, or conduct it in such a way that the UD can be determined.

8.4.3 Conduct the UD test at either the mid-level or high-level point specified in Section 7.1. Introduce the reference gas to the CEMS. Record the CEMS response and subtract the reference value from the CEMS value, and express the absolute value of the difference as a percentage of the span value (see example data sheet in Figure 12A-1). For the reference gas, the absolute value of the difference between the CEMS response and the reference value shall not exceed 5 percent of the span value. If this specification is not met, identify and correct the problem before proceeding.

8.5 ZD Test Procedure.

8.5.1 ZD Test Period. While the affected facility is operating at more than 50 percent of normal load, or as specified in an applicable subpart, determine the magnitude of the ZD once each day (at 24-hour intervals, to the extent practicable) for 7 consecutive unit operating days according to the procedure given in Sections 8.5.2 through 8.5.3. The 7 consecutive unit operating days need not be 7 consecutive calendar days. Use either nitrogen, air, Hg^{B}, or $HgCl_2$ standards for this test.

8.5.2 The purpose of the ZD measurement is to verify the ability of the CEMS to conform to the established CEMS response used for determining emission concentrations or emission rates. Therefore, if periodic automatic or manual adjustments are made to the CEMS zero and response settings, conduct the ZD test immediately before these adjustments, or conduct it in such a way that the ZD can be determined.

8.5.3 Conduct the ZD test at the zero level specified in Section 7.1. Introduce the zero gas to the CEMS. Record the CEMS response and subtract the zero value from the CEMS value and express the absolute value of the difference as a percentage of the span value (see example data sheet in Figure 12A-1). For the zero gas, the absolute value of the difference between the CEMS response and the reference value shall not exceed 5 percent of the span value. If this specification is not met, identify and correct the problem before proceeding.

8.6 RA Test Procedure.

8.6.1 RA Test Period. Conduct the RA test according to the procedure given in Sections 8.6.2 through 8.6.6 while the affected facility is operating at normal full load, or as specified in an applicable subpart. The RA test may be conducted during the ZD and UD test period.

8.6.2 RM. Unless otherwise specified in an applicable subpart of the regulations, use either Method 29 in appendix A to this part, or American Society of Testing and Materials (ASTM) Method D 6784-02 (incorporated by reference in §60.17) as the RM for Hg concentration. Alternatively, an instrumental RM may be used, subject to the approval of the Administrator. Do not include the filterable portion of the sample when making comparisons to the CEMS results. When Method 29 or ASTM D6784-02 is used, conduct the RM test runs with paired or duplicate sampling systems. When an approved instrumental method is used, paired sampling systems are not required. If the RM and CEMS measure on a different moisture basis, data derived with Method 4 in appendix A to this part shall also be obtained during the RA test.

8.6.3 Sampling Strategy for RM Tests. Conduct the RM tests in such a way that they will yield results representative of the emissions from the source and can be compared to the CEMS data. It is preferable to conduct moisture measurements (if needed) and Hg measurements simultaneously, although moisture measurements that are taken within an hour of the Hg measurements may be used to adjust the Hg concentrations to a consistent moisture basis. In order to correlate the CEMS and RM data properly, note the beginning and end of each RM test period for each paired RM run (including the exact time of day) on the CEMS chart recordings or other permanent record of output.

8.6.4 Number and length of RM Tests. Conduct a minimum of nine RM test runs. When Method 29 or ASTM D6784-02 is used, only test runs for which the data from the paired RM trains meet the relative deviation (RD) criteria of this PS shall be used in the RA calculations. In addition, for Method 29 and ASTM D 6784-02, use a minimum sample run time of 2 hours.

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

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

8.6.6 Paired RM Outliers.

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

$$\mathbf{RD = 100 \times *(C_a - C_b)*/(C_a + C_b)} \qquad \textbf{(Eq. 12A-1)}$$

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

8.6.6.2 A minimum performance criteria for RM Hg data is that RD for any data pair must be #10 percent as long as the mean Hg concentration is greater than 1.0 µg/m^3. If the mean Hg concentration is less than or equal to 1.0 µg/m^3, the RD must be #20 percent. Pairs of RM data exceeding these RD criteria should be eliminated from the data set used to develop a Hg CAMS correlation or to assess CAMS RA.

8.6.7 Calculate the mean difference between the RM and CAMS values in the units of micrograms per cubic meter (:g/m^3), the standard deviation, the confidence coefficient, and the RA according to the procedures in Section 12.0.

8.7 Reporting. At a minimum (check with the appropriate EPA Regional Office, State or local Agency for additional requirements, if any), summarize in tabular form the results of the RD tests and the RA tests or alternative RA procedure, as appropriate. Include all data sheets, calculations, charts (records of CAMS responses), reference gas concentration certifications, and any other information necessary to confirm that the performance of the CAMS meets the performance criteria.

9.0 Quality Control. [Reserved]

10.0 Calibration and Standardization. [Reserved]

11.0 Analytical Procedure.

Sample collection and analysis are concurrent for this PS (see Section 8.0). Refer to the RM employed for specific analytical procedures.

12.0 Calculations and Data Analysis.

Summarize the results on a data sheet similar to that shown in Figure 2-2 for PS 2.

12.1 Consistent Basis. All data from the RM and CAMS must be compared in units of :g/m^3, on a consistent and identified moisture and volumetric basis (STP = 20°C, 760 millimeters (mm) Hg).

12.1.1 Moisture Correction (as applicable). If the RM and CAMS measure Hg on a different moisture basis, use Equation 12A-2 to make the appropriate corrections to the Hg concentrations.

$$\text{Concentration}_{(dry)} = \frac{\text{Concentration}_{(wet)}}{(1-B_{ws})} \qquad \textbf{(Eq. 12A-2)}$$

In Equation 12-A-2, B_{ws} is the moisture content of the flue gas from Method 4, expressed as a decimal fraction (e.g., for 8.0 percent H_2O, $B_{ws} = 0.08$).

12.2 Arithmetic Mean. Calculate the arithmetic mean of the difference, d, of a data set as follows:

$$\overline{d} = \frac{1}{n} \sum_{i=1}^{n} d_i \qquad \textbf{(Eq. 12A-3)}$$

Where:

n = Number of data points.

12.3 Standard Deviation. Calculate the standard deviation, S_d, as follows:

$$S_d = \left[\frac{\displaystyle\sum_{i=1}^{n} d_i^2 - \frac{\left[\displaystyle\sum_{i=1}^{n} d_i\right]^2}{n}}{n-1} \right]^{\frac{1}{2}} \qquad \textbf{(Eq. 12A-4)}$$

Where:

$\sum_{i=1}^{n} d_i$ = Algebraic summation of the individual differences d_i.

12.4 Confidence Coefficient (CC). Calculate the 2.5 percent error confidence coefficient (one-tailed), CC, as follows:

$$CC = t_{0.975} \frac{S_d}{\sqrt{n}} \qquad \textbf{(Eq. 12A-5)}$$

12.5 RA. Calculate the RA of a set of data as follows:

$$RA = \frac{\left[\left|\bar{d}\right| + \left|CC\right|\right]}{\overline{RM}} \times 100 \qquad \textbf{(Eq. 12A-6)}$$

Where:

$|\bar{d}|$ = Absolute value of the mean differences (from Equation 12A-3).
$|CC|$ = Absolute value of the confidence coefficient (from Equation 12A-5).
$\overline{RM}$ = Average RM value.

13.0 Method Performance.

13.1 ME. ME is assessed at zero-level, mid-level and high-level values as given below using standards for both Hg^0 and $HgCl_2$. The mean difference between the indicated CAMS concentration and the reference concentration value for each standard shall be no greater than 5 percent of the span value.

13.2 UD. The UD shall not exceed 5 percent of the span value on any of the 7 days of the UD test.

13.3 ZD. The ZD shall not exceed 5 percent of the span value on any of the 7 days of the ZD test.

13.4 RA. The RA of the CAMS must be no greater than 20 percent of the mean value of the RM test data in terms of units of :g/m^3. Alternatively, if the mean RM is less than

5.0 :g/m^3, the results are acceptable if the absolute value of the difference between the mean RM and CAMS values does not exceed 1.0 :g/m^3.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 Alternative Procedures. [Reserved]

17.0 Bibliography.

17.1 40 CFR part 60, appendix B, “Performance Specification 2 - Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources.”

17.2 40 CFR part 60, appendix A, “Method 29 - Determination of Metals Emissions from Stationary Sources.”

17.3 ASTM Method D6784-02, “Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method).”

18.0 Tables and Figures.

TABLE 12A-1. t-VALUES.

n^a	$t_{0.975}$	n^a	$t_{0.975}$	n^a	$t_{0.975}$
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	15	2.145
6	2.571	11	2.228	16	2.131

[a] The values in this table are already corrected for n-1 degrees of freedom. Use n equal to the number of individual values.

	Date	Time	Reference Gas Value :g/m^3	CAMS Measured Value :g/m^3	Absolute Difference	Drift or Measurement Error (% of span value)
Zero Level						
Mid-level						
High-level						

Figure 12A-1. ME, ZD and UD Determination.

* * * * *

PART 72 — PERMITS REGULATION

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

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

16. Section 72.2 is amended in the definition of "Continuous emission monitoring system or CAMS" by revising the introductory text and adding paragraph (7); and by adding, in alphabetical order, a new definition for "sorbent trap monitoring system," to read as follows:

§72.2 Definitions

* * * * *

Continuous emission monitoring system *or* CAMS means the equipment required by part 75 of this chapter used to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of SO_2, NO_x, Hg, or CO_2 emissions or stack gas volumetric flow rate. The following are the principal types of continuous emission monitoring systems required under part 75 of this chapter. Sections 75.10 through 75.18, §75.71(a) and 75.81 of this chapter indicate which type(s) of CAMS is required for specific applications:

* * * * *

(7) A Hg concentration monitoring system, consisting of a Hg pollutant concentration monitor and an automated

DAHS. A Hg concentration monitoring system provides a permanent, continuous record of Hg emissions in units of micrograms per standard cubic meter (:g/scm).

* * * * *

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

* * * * *

PART 75 — CONTINUOUS EMISSION MONITORING

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

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

18. Section 75.2 is amended by adding paragraph (d), to read as follows:

§75.2 Applicability.

* * * * *

(d) The provisions of this part apply to sources subject to a State or Federal mercury (Hg) mass emission reduction program, to the extent that these provisions are adopted as requirements under such a program.

* * * * *

19. Section 75.10 is amended by revising the second sentence of paragraph (d)(1) and revising the first sentence of paragraph (d)(3) to read as follows:

§75.10 General operating requirements.

* * * * *

(d) * * * * *

(1) * * * * * The owner or operator shall reduce all SO_2 concentrations, volumetric flow, SO_2 mass emissions, CO_2 concentration, O_2 concentration, CO_2 mass emissions (if applicable), NO_x concentration, NO_x emission rate, and Hg

concentration data collected by the monitors to hourly averages.

* * * * *

(3) Failure of an SO_2, CO_2, or O_2 emissions concentration monitor, NO_x concentration monitor, Hg concentration monitor, flow monitor, moisture monitor, or NO_x-diluent continuous emission monitoring system to acquire the minimum number of data points for calculation of an hourly average in paragraph (d)(1) of this section shall result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. * * * * *

* * * * *

20. Section 75.15 is added to read as follows:

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

For an affected coal-fired unit under a State or Federal Hg mass emission reduction program that adopts the provisions of subpart I of this part, if the owner or operator elects to use sorbent trap monitoring systems (as defined in §72.2 of this chapter) to quantify Hg mass emissions, the guidelines in paragraphs (a) through (j) of this section shall be followed for this excepted monitoring methodology:

(a) For each sorbent trap monitoring system (whether primary or redundant backup), the use of paired sorbent traps, as described in appendix K to this part, is required;

(b) Each sorbent trap shall have both a main section, a backup section, and a third section to allow spiking with a calibration gas of known Hg concentration, as described in appendix K to this part;

(c) A certified flow monitoring system is required;

(d) Correction for stack gas moisture content is required, and in some cases, a certified O_2 or CO_2 monitoring system is required (see §75.81(a)(4));

(e) Each sorbent trap monitoring system shall be installed and operated in accordance with appendix K to this part. The automated data acquisition and handling system shall ensure that the sampling rate is proportional to the stack gas volumetric flow rate.

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

(g) After each sample collection period, the mass of Hg adsorbed in each sorbent trap (in all three sections) shall be determined according to the applicable procedures in appendix K to this part.

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

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

(j) Initial certification requirements and additional quality-assurance requirements for the sorbent trap monitoring systems are found in §75.20(c)(9), in section 6.5.7 of appendix A to this part, in sections 1.5 and 2.3 of appendix B to this part, and in appendix K to this part.

21. Section 75.20 is amended by:

a. Revising paragraph (a)(5)(i);

b. Revising the first sentence of paragraph (b) introductory text;

c. Revising paragraph (c)(1);

d. Redesignating existing paragraphs (c)(9) and (c)(10) as paragraphs (c)(10) and (c)(11), respectively;

e. Adding a new paragraph (c)(9); and

f. Revising paragraph (d)(2)(v).

The revisions and additions read as follows:

<u>§75.20 Initial certification and recertification procedures</u>.

(a) * * * * *

(5) * * * * *

(i) Until such time, date, and hour as the continuous emission monitoring system can be adjusted, repaired, or replaced and certification tests successfully completed (or, if the conditional data validation procedures in paragraphs (b)(3)(ii) through (b)(3)(ix) of this section are used, until a probationary calibration error test is passed following corrective actions in accordance with paragraph (b)(3)(ii) of this section), the owner or operator shall substitute the following values, as applicable, for each hour of unit operation during the period of invalid data specified in paragraph (a)(4)(iii) of this section or in §75.21: the maximum potential concentration of SO_2, as defined in section 2.1.1.1 of appendix A to this part, to report SO_2 concentration; the maximum potential NO_x emission rate, as defined in §72.2 of this chapter, to report NO_x emissions in lb/MMBtu; the maximum potential concentration of NO_x, as defined in section 2.1.2.1 of appendix A to this part, to report NO_x emissions in ppm (when a NO_x concentration monitoring system is used to determine NO_x mass emissions, as defined under §75.71(a)(2)); the maximum potential concentration of Hg, as defined in section 2.1.7 of appendix A to this part, to report Hg emissions in :g/scm (when a Hg concentration monitoring system or a sorbent trap monitoring system is used to determine Hg mass emissions, as defined under §75.81(b)); the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, to report volumetric flow; the maximum potential concentration of CO_2, as defined in section 2.1.3.1 of appendix A to this part, to report CO_2 concentration data; and either the minimum potential moisture percentage, as defined in section 2.1.5 of appendix A to this part or, if Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_x emission rate, the maximum potential moisture percentage, as defined in section 2.1.6 of appendix A to this part; and

* * * * *

(b) Recertification approval process. Whenever the owner or operator makes a replacement, modification, or change in a certified continuous emission monitoring system or continuous opacity monitoring system that may significantly affect the ability of the system to accurately measure or record the SO_2 or CO_2 concentration, stack gas volumetric flow rate, NO_x emission rate, NO_x concentration, Hg concentration, percent moisture, or opacity, or to meet the requirements of §75.21 or appendix B to this part, the owner or operator shall recertify the continuous emission monitoring system or continuous opacity monitoring system, according to the procedures in this paragraph. * * * * *

* * * * *

(c) * * * * *

(1) For each SO_2 pollutant concentration monitor, each

NO_x concentration monitoring system used to determine NO_x mass emissions, as defined under §75.71(a)(2), each Hg concentration monitoring system, and each NO_x-diluent continuous emission monitoring system:

(i) A 7-day calibration error test, where, for the NO_x-diluent continuous emission monitoring system, the test is performed separately on the NO_x pollutant concentration monitor and the diluent gas monitor;

(ii) A linearity check, where, for the NO_x-diluent continuous emission monitoring system, the test is performed separately on the NO_x pollutant concentration monitor and the diluent gas monitor. For Hg monitors, perform this check with elemental Hg standards;

(iii) A relative accuracy test audit. For the NO_x-diluent continuous emission monitoring system, the RATA shall be done on a system basis, in units of lb/MMBtu. For the NO_x concentration monitoring system, the RATA shall be done on a ppm basis. For the Hg concentration monitoring system, the RATA shall be done on a :g/scm basis;

(iv) A bias test;

(v) A cycle time test; and

(vi) For Hg monitors only, a 3-level system integrity check, using a NIST-traceable source of oxidized Hg, as described in section 6.2 of appendix A to this part. This test is not required for an Hg monitor that does not have a converter.

* * * * *

(9) For each sorbent trap monitoring system, perform a RATA, on a :g/dscm basis, and a bias test.

* * * * *

(d) * * * * *

(2) * * * * *

(v) For each parameter monitored (i.e., SO_2, CO_2, O_2, NO_x, Hg or flow rate) at each unit or stack, a regular non-redundant backup CAMS may not be used to report data at that affected unit or common stack for more than 720 hours in any one calendar year (or 720 hours in any ozone season, for sources that report emission data only during the ozone season, in accordance with §75.74(c)), unless the CAMS passes a RATA at that unit or stack. For each parameter monitored at each unit or stack, the use of a like-kind replacement non-redundant backup analyzer (or analyzers) is restricted to 720 cumulative hours per calendar year (or ozone season, as applicable), unless the owner or operator redesignates the like-kind replacement analyzer(s) as component(s) of regular non-redundant backup CAMS and each redesignated CAMS passes a RATA at that unit or stack.

* * * * *

22. Section 75.21 is amended by revising paragraph (a)(3) to read as follows:

§75.21 Quality assurance and quality control requirements.

(a) * * * * *

(3) The owner or operator shall perform quality assurance upon a reference method backup monitoring system according to the requirements of method 2, 6C, 7E, or 3A in appendix A of part 60 of this chapter (supplemented, as necessary, by guidance from the Administrator), or one of the Hg reference methods in §75.22, as applicable, instead of the procedures specified in appendix B of this part.

* * * * *

23. Section 75.22 is amended by adding new paragraphs (a)(7) and (b)(5), to read as follows:

§75.22 Reference methods.

(a) * * * * *

(7) ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound, and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (also known as the Ontario-Hydro Method) is the reference method for determining Hg concentration. When this method is used, paired sampling trains are required, and to validate a RATA run, the relative deviation (RD), calculated according to section 11.7 of appendix K to this part, must not exceed 10

percent. If the RD criterion is met, use the average Hg concentration measured by the two trains (vapor phase Hg, only) in the relative accuracy calculations. Alternatively, an instrumental reference method capable of measuring total vapor phase Hg may be used, subject to the approval of the Administrator.

(b) * * * * *

(5) ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound, and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (also known as the Ontario-Hydro Method) for determining Hg concentration. Alternatively, an instrumental reference method capable of measuring total vapor phase Hg may be used, subject to the approval of the Administrator.

* * * * *

24. Section 75.24 is amended by revising paragraph (d), to read as follows:

§75.24 Out-of-control periods and adjustment for system bias.

* * * * *

(d) When the bias test indicates that an SO_2 monitor, a flow monitor, a NO_x-diluent continuous emission monitoring system, a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in §75.71(a)(2), a

Hg concentration monitoring system or a sorbent trap monitoring system is biased low (i.e., the arithmetic mean of the differences between the reference method value and the monitor or monitoring system measurements in a relative accuracy test audit exceed the bias statistic in section 7 of appendix A to this part), the owner or operator shall adjust the monitor or continuous emission monitoring system to eliminate the cause of bias such that it passes the bias test or calculate and use the bias adjustment factor as specified in section 2.3.4 of appendix B to this part.

*   *   *   *   *

25. Section 75.31 is amended by:

a. Revising the first sentence of paragraph (a);

b. Revising paragraph (b) introductory text; and

c. Revising paragraphs (b)(1) and (b)(2).

The revisions read as follows:

§75.31 Initial missing data procedures.

(a) During the first 720 quality-assured monitor operating hours following initial certification of the required SO_2, CO_2, O_2, Hg concentration, or moisture monitoring system(s) at a particular unit or stack location

*   *   *   *   *

(b) SO_2, CO_2, or O_2 concentration data, Hg concentration data, and moisture data. For each hour of missing SO_2, Hg, or CO_2 emissions concentration data (including CO_2 data converted from O_2 data using the procedures in appendix F of this part), or missing O_2 or CO_2 diluent concentration data used to calculate heat input, or missing moisture data, the owner or operator shall calculate the substitute data as follows:

(1) Whenever prior quality-assured data exist, the owner or operator shall substitute, by means of the data acquisition and handling system, for each hour of missing data, the average of the hourly SO_2, CO_2, Hg, or O_2 concentrations, or moisture percentages recorded by a certified monitor for the unit operating hour immediately before and the unit operating hour immediately after the missing data period.

(2) Whenever no prior quality assured SO_2, CO_2, Hg, or O_2 concentration data, or moisture data exist, the owner or operator shall substitute, as applicable, for each hour of missing data, the maximum potential SO_2 concentration or the maximum potential CO_2 concentration or the minimum potential O_2 concentration or (unless Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_x emission rate) the minimum potential moisture percentage, or the maximum potential Hg concentration, as specified, respectively, in sections

2.1.1.1, 2.1.3.1, 2.1.3.2, 2.1.5, and 2.1.7 of appendix A to this part. If Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_x emission rate, substitute the maximum potential moisture percentage, as specified in section 2.1.6 of appendix A to this part.

* * * * *

26. Section 75.32 is amended by revising the first sentence of paragraph (a) introductory text to read as follows:

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

(a) Following initial certification of the required SO_2, CO_2, O_2, or Hg concentration, or moisture monitoring system(s) at a particular unit or stack location * * * * *

* * * * *

27. Table 1 in §75.33 is revised as follows:

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

* * * * *

Table 1. Missing Data Procedure for SO_2 CAMS, CO_2 CAMS, Moisture CAMS, Hg CAMS, and Diluent (CO_2 or O_2) Monitors for Heat Input Determination

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CAMS outage (hours)[2]	Method	Lookback period
95 or more . . (90 or more for Hg)	N # 24	Average	HB/HA
	N > 24	For SO_2, CO_2, Hg, and H_2O[**], the greater of:	
		Average	HB/HA
		90th percentile	720 hours[*]
		For O_2 and H_2O[x], the lesser of:	
		Average	HB/HA
		10th percentile	720 hours[*]
90 or more, but below 95 . . . (≥ 80 but < 90 for Hg)	N # 8	Average	HB/HA
	N > 8	For SO_2, CO_2, Hg, and H_2O[**], the greater of:	
		Average	HB/HA
		95th percentile	720 hours[*]
		For O_2 and H_2O[x], the lesser of:	
		Average	HB/HA
		5th percentile	720 hours[*]
80 or more, but below 90........... (≥70 but < 80 for Hg)	N > 0	For SO_2, CO_2, Hg, and H_2O[**],	
		Maximum value[1]	720 hours[*]
		For O_2 and H_2O[x]:	
		Minimum value[1]	720 hours[*]

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CAMS outage (hours)[2]	Method	Lookback period
Below 80............ (Below 70 for Hg)	N > 0	Maximum potential concentration or % (for SO_2, CO_2, Hg, and H_2O^{**}) *or* Minimum potential concentration or % (for O_2 and H_2O^{x})	None

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

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

[1] Where a unit with add-on SO_2 or Hg emission controls can demonstrate that the controls are operating properly, as provided in §75.34, the unit may, upon approval, use the maximum controlled emission rate from the previous 720 operating hours.

[2] During unit operating hours.

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

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

* * * * *

28. Subpart D is further amended by adding two new sections, §75.38 and §75.39, to read as follows:

§75.38 Standard missing data procedures for Hg CAMS.

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

(b) For a unit equipped with a flue gas desulfurization (FGD) system that significantly reduces the concentration of Hg emitted to the atmosphere (including circulating fluidized bed units that use limestone injection), or for a unit equipped with add-on Hg emission controls (e.g. , carbon injection), the standard missing data procedures in paragraph (a) of this section may only be used for hours in which the SO_2 or Hg emission controls are documented to be operating properly, as described in §75.58(b)(3). For any hour(s) in the missing data period for which this documentation is unavailable, the owner or operator shall report, as applicable, the maximum potential Hg concentration, as defined in section 2.1.7 of appendix A to this part. In addition, under §75.64(c), the designated representative shall submit as part of each electronic quarterly report, a certification statement, verifying the proper operation of the SO_2 or Hg emission controls for each missing data period in which the procedures in paragraph (a) of this section are applied.

(c) For units with FGD systems or add-on Hg controls, when the percent monitor data availability is less than 80.0 percent, and a missing data period occurs, the owner or operator may petition to report the maximum controlled Hg concentration in the previous 720 quality-assured monitor operating hours, consistent with §75.34(a)(3).

§75.39 Missing data procedures for sorbent trap monitoring systems.

(a) If a sorbent trap monitoring system has not been certified by the applicable compliance date specified under a State or Federal Hg mass emission reduction program that adopts the requirements of subpart I of this part, the owner or operator shall report the maximum potential Hg concentration, as defined in section 2.1.7 of appendix A to this part, until the system is certified.

(b) For a certified sorbent trap system, a missing data period will occur whenever:

(1) A gas sample is not extracted from the stack (e.g. during a monitoring system malfunction or when the system

undergoes maintenance); or

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

(c) Initial missing data procedures. Use these missing data procedures until 720 hours of quality-assured data have been collected with the sorbent trap monitoring system(s), following initial certification. For each hour of the missing data period, the substitute data value for Hg concentration shall be the average Hg concentration from all valid sorbent trap analyses to date, including data from the initial certification test runs.

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

(1) If the percent monitor data availability (PMA) is $\geq$ 90.0 percent, report the average Hg concentration for all valid sorbent trap analyses in the previous 12 months.

(2) If the PMA is $\geq$ 80.0 percent, but < 90.0 percent, report the 95th percentile Hg concentration obtained from all of the valid sorbent trap analyses in the previous 12 months.

(3) If the PMA is $\geq$ 70.0 percent, but < 80.0 percent, report the maximum Hg concentration obtained from all of the valid sorbent trap analyses in the previous 12 months.

(4) If the PMA is < 70.0 percent, report the maximum potential Hg concentration, as defined in section 2.1.7 of appendix A to this part.

(5) For the purposes of paragraphs (d)(1), (d)(2), and (d)(3) of this section, if fewer than 12 months have elapsed since initial certification, use whatever valid sorbent trap analyses are available to determine the appropriate substitute data values.

(e) Notwithstanding the requirements of paragraphs (c) and (d) of this section, if the unit has add-on Hg emission controls or is equipped with a flue gas desulfurization system that significantly reduces Hg emissions, the owner or operator shall report the maximum potential Hg concentration, as defined in section 2.1.7 of appendix A to this part, for any hour(s) in the missing data period for which proper operation of the Hg emission controls or FGD system is not documented according to §75.58(b)(3).

29. Section 75.53 is amended by:

a. Revising paragraph (e)(1)(i)(E);

b. Revising paragraph (e)(1)(iv) introductory text; and

c. Revising paragraph (e)(1)(x).

The revisions read as follows:

§75.53 Monitoring plan.

* * * * *

(e) * * * * *

(1) * * * * *

(i) * * * * *

(E) Type(s) of emission controls for SO_2, NO_x, Hg, and particulates installed or to be installed, including specifications of whether such controls are pre-combustion, post-combustion, or integral to the combustion process; control equipment code, installation date, and optimization date; control equipment retirement date (if applicable); primary/secondary controls indicator; and an indicator for whether the controls are an original installation;

* * * * *

(iv) Identification and description of each monitoring component (including each monitor and its identifiable components, such as analyzer and/or probe) in the CAMS (e.g., SO_2 pollutant concentration monitor, flow monitor, moisture monitor; NO_x pollutant concentration monitor, Hg monitor, and diluent gas monitor), the sorbent trap monitoring system, the continuous opacity monitoring system, or the excepted monitoring system (e.g., fuel flowmeter, data acquisition and handling system), including:

* * * * *

(x) For each parameter monitored: scale, maximum potential concentration (and method of calculation), maximum expected concentration (if applicable) (and method of calculation), maximum potential flow rate (and method of calculation), maximum potential NO_x emission rate, span value, full-scale range, daily calibration units of measure, span effective date/hour, span inactivation date/hour, indication of whether dual spans are required, default high range value, flow rate span, and flow rate span value and full scale value (in scfh) for each unit or stack using SO_2, NO_x, CO_2, O_2, Hg, or flow component monitors.

* * * * *

30. Section 75.57 is amended by adding new paragraphs (i) and (j), to read as follows:

§75.57 General recordkeeping provisions.

* * * * *

(i) Hg emission record provisions (CAMS). The owner or operator shall record for each hour the information required by this paragraph for each affected unit using Hg CAMS in combination with flow rate, and (in certain cases) moisture, and diluent gas monitors, to determine Hg mass emissions and (if applicable) unit heat input under a State or Federal Hg mass emissions reduction program that adopts the requirements of subpart I of this part.

(1) For Hg concentration during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(i) Component-system identification code, as provided in §75.53;

(ii) Date and hour;

(iii) Hourly Hg concentration (:g/scm, rounded to the nearest tenth). For a particular pair of sorbent traps, this will be the flow-proportional average concentration for the data collection period;

(iv) The bias-adjusted hourly average Hg concentration (:g/scm, rounded to the nearest hundredth) if a bias adjustment factor is required, as provided in §75.24(d);

(v) Method of determination for hourly Hg concentration using Codes 1-55 in Table 4a of this section; and

(vi) The percent monitor data availability (to the nearest tenth of a percent), calculated pursuant to §75.32.

(2) For flue gas moisture content during unit operation (if required), as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination (except where a default moisture value is used in accordance with §75.11(b), §75.12(b), or approved under §75.66):

(i) Component-system identification code, as provided in §75.53;

(ii) Date and hour;

(iii) Hourly average moisture content of flue gas (percent, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the wet- and dry-basis oxygen hourly averages (in percent O_2, rounded to the nearest tenth);

(iv) Percent monitor data availability (recorded to the nearest tenth of a percent) for the moisture monitoring system, calculated pursuant to §75.32; and

(v) Method of determination for hourly average moisture percentage, using Codes 1-55 in Table 4a of this section.

(3) For diluent gas (O_2 or CO_2) concentration during unit operation (if required), as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(i) Component-system identification code, as provided in §75.53;

(ii) Date and hour;

(iii) Hourly average diluent gas (O_2 or CO_2) concentration (in percent, rounded to the nearest tenth);

(iv) Method of determination code for diluent gas (O_2 or CO_2) concentration data using Codes 1-55, in Table 4a of this section; and

(v) The percent monitor data availability (to the nearest tenth of a percent) for the O_2 or CO_2 monitoring system (if a separate O_2 or CO_2 monitoring system is used for heat input determination), calculated pursuant to §75.32.

(4) For stack gas volumetric flow rate during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination, record the information required under paragraphs (c)(2)(i) through

(c)(2)(vi) of this section.

(5) For Hg mass emissions during unit operation, as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination:

(i) Date and hour;

(ii) Hourly Hg mass emissions (ounces, rounded to three decimal places);

(iii) Hourly Hg mass emissions (ounces, rounded to three decimal places), adjusted for bias if a bias adjustment factor is required, as provided in §75.24(d); and

(iv) Identification code for emissions formula used to derive hourly Hg mass emissions from Hg concentration, flow rate and moisture data, as provided in §75.53.

(j) Hg emission record provisions (sorbent trap systems). The owner or operator shall record for each hour the information required by this paragraph, for each affected unit using sorbent trap monitoring systems in combination with flow rate, moisture, and (in certain cases) diluent gas monitors, to determine Hg mass emissions and (if required) unit heat input under a State or Federal Hg mass emissions reduction program that adopts the requirements of subpart I of this part.

(1) For Hg concentration during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(i) Component-system identification code, as provided in §75.53;

(ii) Date and hour;

(iii) Hourly Hg concentration (:g/dscm, rounded to the nearest tenth). For a particular pair of sorbent traps, this will be the flow-proportional average concentration for the data collection period;

(iv) The bias-adjusted hourly average Hg concentration (:g/dscm, rounded to the nearest tenth) if a bias adjustment factor is required, as provided in §75.24(d);

(v) Method of determination for hourly average Hg concentration using Codes 1-55 in Table 4a of this section; and

(vi) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated pursuant to §75.32;

(2) For flue gas moisture content during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination (except where a

default moisture value is used in accordance with §75.11(b), §75.12(b), or approved under §75.66), record the information required under paragraphs (i)(2)(i) through (i)(2)(v) of this section;

(3) For diluent gas (O_2 or CO_2) concentration during unit operation (if required for heat input determination), record the information required under paragraphs (i)(3)(i) through (i)(3)(v) of this section.

(4) For stack gas volumetric flow rate during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination, record the information required under paragraphs (c)(2)(i) through (c)(2)(vi) of this section.

(5) For Hg mass emissions during unit operation, as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination, record the information required under paragraph (i)(5) of this section.

(6) Record the average flow rate of stack gas through each sorbent trap (in appropriate units, e.g., liters/min, cc/min, dscm/min).

(7) Record the dry gas meter reading (in dscm, rounded

to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period.

(8) Calculate and record the ratio of the bias-adjusted stack gas flow rate to the sample flow rate, as described in section 11.2 of appendix K to this part.

31. Section 75.58 is amended by revising paragraphs (b)(3) introductory text, (b)(3)(i), and (b)(3)(ii), to read as follows:

§75.58 General recordkeeping provisions for specific situations.

* * * * *

(b) * * * * *

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

(i) Parametric data which demonstrate, for each hour of missing SO_2, Hg, or NO_x emission data, the proper operation of the add-on emission controls, as described in the quality assurance/quality control program for the unit. The parametric data shall be maintained on site and shall be submitted, upon request, to the Administrator, EPA Regional office, State, or local agency. Alternatively, for units equipped with flue gas desulfurization (FGD) systems, the owner or operator may use quality-assured data from a certified SO_2 monitor to demonstrate proper operation of the emission controls during periods of missing Hg data;

(ii) A flag indicating, for each hour of missing SO_2, Hg, or NO_x emission data, either that the add-on emission controls are operating properly, as evidenced by all parameters being within the ranges specified in the quality assurance/quality control program, or that the add-on emission controls are not operating properly;

* * * * *

32. Section 75.59 is amended by:

a. Revising the introductory text of paragraphs (a)(1), (a)(3),(a)(5), (a)(5)(ii), (a)(6), and (a)(9);

b. Adding paragraphs (a)(7)(vii), (a)(7)(viii), and (a)(14);

c. Revising paragraph (a)(9)(vi); and

d. Revising the introductory text of paragraph (c).

The revisions read as follows:

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

* * * * *

(a) * * * * *

(1) For each SO_2 or NO_X pollutant concentration monitor, flow monitor, CO_2 emissions concentration monitor (including O_2 monitors used to determine CO_2 emissions), Hg monitor, or diluent gas monitor (including wet- and dry-basis O_2 monitors used to determine percent moisture), the owner or operator shall record the following for all daily and 7-day calibration error tests, all daily system integrity checks (Hg monitors, only), and all off-line calibration demonstrations, including any follow-up tests after corrective action:

* * * * *

(3) For each SO_2 or NO_X pollutant concentration monitor, CO_2 emissions concentration monitor (including O_2 monitors used to determine CO_2 emissions), Hg concentration monitor, or diluent gas monitor (including wet- and dry-basis O_2 monitors used to determine percent moisture), the owner or operator shall record the following for the initial and all subsequent linearity check(s) and 3-level system integrity checks (Hg monitors with converters, only), including any follow-up tests after corrective action:

* * * * *

(5) For each SO_2 pollutant concentration monitor, flow monitor, each CO_2 emissions concentration monitor (including any O_2 concentration monitor used to determine CO_2 mass

emissions or heat input), each NO_x-diluent continuous emission monitoring system, each NO_x concentration monitoring system, each diluent gas (O_2 or CO_2) monitor used to determine heat input, each moisture monitoring system, each Hg concentration monitoring system, each sorbent trap monitoring system, and each approved alternative monitoring system, the owner or operator shall record the following information for the initial and all subsequent relative accuracy test audits:

* * * * *

(ii) Individual test run data from the relative accuracy test audit for the SO_2 concentration monitor, flow monitor, CO_2 emissions concentration monitor, NO_x-diluent continuous emission monitoring system, SO_2-diluent continuous emission monitoring system, diluent gas (O_2 or CO_2) monitor used to determine heat input, NO_x concentration monitoring system, moisture monitoring system, Hg concentration monitoring system, sorbent trap monitoring system, or approved alternative monitoring system, including:

* * * * *

(6) For each SO_2, NO_x, Hg, or CO_2 emissions concentration monitor, NO_x-diluent continuous emission monitoring system, NO_x concentration monitoring system, or

diluent gas (O_2 or CO_2) monitor used to determine heat input, the owner or operator shall record the following information for the cycle time test:

* * * * *

(7) * * * * *

(vii) For each RATA run using the Ontario-Hydro method to determine Hg concentration:

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

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

(C) Average stack temperature (^{B}F);

(D) Dry gas volume metered (dscm);

(E) Percent isokinetic;

(F) Particle-bound Hg collected by the filter, blank, and probe rinse (:g);

(G) Oxidized Hg collected by the KCl impingers (:g)

(H) Elemental Hg collected in the HNO_3/H_2O_2 impinger and in the $KMnO_4/H_2SO_4$ impingers (:g);

(I) Total Hg, including particle-bound Hg (:g); and

(J) Total Hg, excluding particle-bound Hg (:g)

(viii) Data elements for instrumental Hg reference method. [Reserved]

* * * * *

(9) When hardcopy relative accuracy test reports, certification reports, recertification reports, or

semiannual or annual reports for gas or flow rate CAMS, Hg CAMS, or sorbent trap monitoring systems are required or requested under §75.60(b)(6) or §75.63, the reports shall include, at a minimum, the following elements (as applicable to the type(s) of test(s) performed:

* * * * *

(vi) Laboratory calibrations of the source sampling equipment. For sorbent trap monitoring systems, the laboratory analyses of all sorbent traps, and information documenting the results of all leak checks and other applicable quality control procedures.

* * * * *

(14) For the sorbent traps used in sorbent trap monitoring systems to quantify Hg concentration under subpart I of this part (including sorbent traps used for relative accuracy testing), the owner or operator shall keep records of the following:

(i) The ID number of the monitoring system in which each sorbent trap was used to collect Hg;

(ii) The unique identification number of each sorbent trap;

(iii) The beginning and ending dates and hours of the data collection period for each sorbent trap;

(iv) The average Hg concentration (in :g/dscm) for the data collection period;

(v) Information documenting the results of the required leak checks;

(vi) The analysis of the Hg collected by each sorbent trap; and

(vii) Information documenting the results of the other applicable quality control procedures in §75.15 and in appendices B and K to this part.

* * * * *

(c) Except as otherwise provided in §75.58(b)(3)(i), units with add-on SO_2 or NO_x emission controls following the provisions of §75.34(a)(1) or (a)(2), and for units with add-on Hg emission controls, the owner or operator shall keep the following records on-site in the quality assurance/quality control plan required by section 1 of appendix B to this part: * * * * *

* * * * *

33. Part 75 is amended by adding Subpart I, to read as follows:

Subpart I — Hg Mass Emission Provisions

<u>§75.80 General provisions</u>.

(a) Applicability. The owner or operator of a unit shall comply with the requirements of this subpart to the extent that compliance is required by an applicable State or

Federal Hg mass emission reduction program that incorporates by reference, or otherwise adopts the provisions of, this subpart.

(1) For purposes of this subpart, the term “affected unit” shall mean any coal-fired unit (as defined in §72.2 of this chapter) that is subject to a State or Federal Hg mass emission reduction program requiring compliance with this subpart. The term “non-affected unit” shall mean any unit that is not subject to such a program, the term “permitting authority” shall mean the permitting authority under an applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart, and the term “designated representative” shall mean the responsible party under the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart.

(2) In addition, the provisions of subparts A, C, D, E, F, and G and appendices A through G of this part applicable to Hg concentration, flow rate, moisture, diluent gas concentration, and heat input, as set forth and referenced in this subpart, shall apply to the owner or operator of a unit required to meet the requirements of this subpart by a State or Federal Hg mass emission reduction program. The requirements of this part for SO_2, NO_x, CO_2

and opacity monitoring, recordkeeping and reporting do not apply to units that are subject only to a State or Federal Hg mass emission reduction program that adopts the requirements of this subpart, but are not affected units under the Acid Rain Program or under a State or Federal NO_x mass emission reduction program that adopts the requirements of subpart H of this part.

(b) Compliance dates. The owner or operator of an affected unit shall meet the compliance deadlines established by an applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart.

(c) Prohibitions.

(1) No owner or operator of an affected unit or a non-affected unit under §75.82(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with paragraph (h) of this section.

(2) No owner or operator of an affected unit or a non-affected unit under §75.82(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged emissions of Hg to the atmosphere without accounting for all such

emissions in accordance with the applicable provisions of this part.

(3) No owner or operator of an affected unit or a non-affected unit under §75.82(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording Hg mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the provisions of this part applicable to monitoring systems under §75.81.

(4) No owner or operator of an affected unit or a non-affected unit under §75.82(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this part, except under any one of the following circumstances:

(i) During the period that the unit is covered by a retired unit exemption that is in effect under the State or Federal Hg mass emission reduction program that adopts the requirements of this subpart; or

(ii) The owner or operator is monitoring Hg mass emissions from the affected unit with another certified monitoring system approved, in accordance with the provisions of paragraph (d) of this section; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system in accordance with §75.61.

(d) Initial certification and recertification procedures.

(1) The owner or operator of an affected unit that is subject to the Acid Rain Program or to a State or Federal NO_x mass emission reduction program that adopts the requirements of subpart H of this part shall comply with the applicable initial certification and recertification procedures in §75.20 and §75.70(d), except that the owner or operator shall meet any additional requirements for Hg concentration monitoring systems, sorbent trap monitoring systems (as defined in §72.2 of this chapter), flow monitors, CO_2 monitors, O_2 monitors, or moisture monitors, as set forth under §75.81, under the common stack provisions in §75.82, or under an applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart.

(2) The owner or operator of an affected unit that is not subject to the Acid Rain Program or to a State or Federal NO_x mass emission reduction program that adopts the

requirements of subpart H of this part shall comply with the initial certification and recertification procedures established by an applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart.

(e) Quality assurance and quality control requirements. For units that use continuous emission monitoring systems to account for Hg mass emissions, the owner or operator shall meet the applicable quality assurance and quality control requirements in §75.21 and appendix B to this part for the flow monitoring systems, Hg concentration monitoring systems, moisture monitoring systems, and diluent monitors required under §75.81. Units using sorbent trap monitoring systems shall meet the applicable quality assurance requirements in §75.15, appendix K to this part, and sections 1.5 and 2.3 of appendix B to this part.

(f) Missing data procedures. Except as provided in §75.38(b) and paragraph (g) of this section, the owner or operator shall provide substitute data from monitoring systems required under §75.81 for each affected unit as follows:

(1) For an owner or operator using an Hg concentration monitoring system, substitute for missing data in accordance

with the applicable missing data procedures in §§75.31 through 75.38 whenever the unit combusts fuel and:

(i) A valid, quality-assured hour of Hg concentration data (in :g/scm) has not been measured and recorded, either by a certified Hg concentration monitoring system, by an appropriate EPA reference method under §75.22, or by an approved alternative monitoring method under subpart E of this part; or

(ii) A valid, quality-assured hour of flow rate data (in scfh) has not been measured and recorded for a unit either by a certified flow monitor, by an appropriate EPA reference method under §75.22, or by an approved alternative monitoring system under subpart E of this part; or

(iii) A valid, quality-assured hour of moisture data (in percent H_2O) has not been measured or recorded for an affected unit, either by a certified moisture monitoring system, by an appropriate EPA reference method under §75.22, or an approved alternative monitoring method under subpart E of this part. This requirement does not apply when a default percent moisture value, as provided in §75.11(b) or §75.12(b), is used to account for the hourly moisture content of the stack gas, or when correction of the Hg concentration for moisture is not necessary; or

(iv) A valid, quality-assured hour of heat input rate data (in MMBtu/hr) has not been measured and recorded for a unit, either by certified flow rate and diluent (CO_2 or O_2) monitors, by appropriate EPA reference methods under §75.22, or by approved alternative monitoring systems under subpart E of this part, where heat input is required for allocating allowances under the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart.

(2) For an owner or operator using a sorbent trap monitoring system to quantify Hg mass emissions, substitute for missing data in accordance with the missing data procedures in §75.39.

(g) Reporting data prior to initial certification. If, by the applicable compliance date under the State or Federal Hg mass emission reduction program that adopts the requirements of this subpart, the owner or operator of an affected unit has not successfully completed all required certification tests for any monitoring system(s), he or she shall determine, record and report hourly data prior to initial certification using one of the following procedures, for the monitoring system(s) that are uncertified:

(1) For Hg concentration and flow monitoring systems, report the maximum potential concentration of Hg as defined in section 2.1.7 of appendix A to this part and the maximum

potential flow rate, as defined in section 2.1.4.1 of appendix A to this part; or

(2) For any unit, report data from the reference methods under §75.22; or

(3) For any unit that is required to report heat input for purposes of allocating allowances, report (as applicable) the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, the maximum potential CO_2 concentration, as defined in section 2.1.3.1 of appendix A to this part, the minimum potential O_2 concentration, as defined in section 2.1.3.2 of appendix A to this part, and the minimum potential percent moisture, as defined in section 2.1.5 of appendix A to this part.

(h) Petitions.

(1) The designated representative of an affected unit that is also subject to the Acid Rain Program may submit a petition to the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of §75.66 and any additional requirements established by the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart. Use of an alternative to any requirement of this subpart is in accordance with this subpart and with such State or Federal Hg mass emission reduction program

only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

(2) Notwithstanding paragraph (h)(1) of this section, petitions requesting an alternative to a requirement concerning any additional CAMS required solely to meet the common stack provisions of §75.82 shall be submitted to the permitting authority and the Administrator and shall be governed by paragraph (h)(3) of this section. Such a petition shall meet the requirements of §75.66 and any additional requirements established by an applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart.

(3) The designated representative of an affected unit that is not subject to the Acid Rain Program may submit a petition to the permitting authority and the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of §75.66 and any additional requirements established by the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart. Use of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that it is approved in writing by the Administrator, in consultation

with the permitting authority.

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

The owner or operator of the affected coal-fired unit shall either:

(a) Meet the general operating requirements in §75.10 for the following continuous emission monitors (except as provided in accordance with subpart E of this part):

(1) A Hg concentration monitoring system (as defined in §72.2 of this chapter) or a sorbent trap monitoring system (as defined in §72.2 of this chapter) to measure Hg concentration; and

(2) A flow monitoring system; and

(3) A continuous moisture monitoring system (if correction of Hg concentration for moisture is required), as described in §75.11(b) or §75.12(b). Alternatively, the owner or operator may use the appropriate fuel-specific default moisture value provided in §75.11 or §75.12, or a site-specific moisture value approved by petition under §75.66; and

(4) If heat input is required to be reported under the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart, the owner or operator also must meet the general operating

requirements for a flow monitoring system and an O_2 or CO_2 monitor to measure heat input rate; or

(b) For an affected unit that emits 464 ounces (29 lb) of Hg per year or less, use the following excepted monitoring methodology. To implement this methodology for a qualifying unit, the owner or operator shall meet the general operating requirements in §75.10 for the continuous emission monitors described in paragraphs (a)(2) and (a)(4) of this section, and perform Hg emission testing for initial certification and on-going quality-assurance, as described in paragraphs (c) through (e) of this section.

(c) To determine whether an affected unit is eligible to use the monitoring provisions in paragraph (b) of this section:

(1) The owner or operator must perform Hg emission testing prior to the compliance date in §75.80(b), to determine the Hg concentration (i.e., total vapor phase Hg) in the effluent. The testing shall be performed using one of the Hg reference methods listed in §75.22, and shall consist of a minimum of 3 runs at the normal unit operating load. The minimum time per run shall be 1 hour if an instrumental reference method is used. If the Ontario-Hydro method is used, the test runs must be long enough to ensure that sufficient Hg is collected to analyze. If the unit is

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

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

$$E = 8760\ K\ C_{Hg}\ Q_{max} \qquad \text{(Eq. 1)}$$

Where:

E = Estimated annual Hg mass emissions from the affected unit (ounces/year)
K = Units conversion constant, 9.978×10^{-10} oz-scm/:g-scf
8760 = Number of hours in a year
C_{Hg} = The highest Hg concentration (:g/scm) from any of the test runs or 0.50 :g/scm, whichever is greater
Q_{max} = Maximum potential flow rate, determined according to section 2.1.4.1 of appendix A to this part (scfh)

Equation 1 of this section assumes that the unit operates year-round at its maximum potential flow rate. Also, note that if the highest Hg concentration measured in any test run is less than 0.50 :g/scm, a default value of 0.50 :g/scm must be used in the calculations.

(3) If the estimated annual Hg mass emissions from

paragraph (c)(2) of this section are 464 ounces per year or less, then the unit is eligible to use the monitoring provisions in paragraph (b) of this section, and continuous monitoring of the Hg concentration is not required (except as otherwise provided in paragraphs (e) and (f) of this section).

(d) If the owner or operator of an eligible unit under paragraph (c)(3) of this section elects not to continuously monitor Hg concentration, then the following requirements must be met:

(1) The results of the Hg emission testing performed under paragraph (c) of this section shall be submitted as a certification application to the Administrator and to the permitting authority, no later than 45 days after the testing is completed. The calculations demonstrating that the unit emits 464 ounces (or less) per year of Hg shall also be provided, and the default Hg concentration that will be used for reporting under §75.84 shall be specified in both the electronic and hard copy portions of the monitoring plan for the unit. The methodology is considered to be provisionally certified as of the date and hour of completion of the Hg emission testing.

(2) Following initial certification, the same default Hg concentration value that was used to estimate the unit’s

annual Hg mass emissions under paragraph (c) of this section shall be reported for each unit operating hour, except as otherwise provided in paragraph (d)(6) of this section. The default Hg concentration value shall be updated as appropriate, according to paragraph (d)(5) of this section.

(3) The hourly Hg mass emissions shall be calculated according to section 9.1.3 in appendix F to this part.

(4) The Hg emission testing described in paragraph (c) of this section shall be repeated periodically, for the purposes of quality-assurance, as follows:

(i) If the results of the certification testing under paragraph (c) of this section show that the unit emits 144 ounces (9 lb) of Hg per year or less, the first retest is required by the end of the fourth QA operating quarter (as defined in §72.2 of this chapter) following the calendar quarter of the certification testing; or

(ii) If the results of the certification testing under paragraph (c) of this section show that the unit emits more than 144 ounces of Hg per year, but less than or equal to 464 ounces per year, the first retest is required by the end of the second QA operating quarter (as defined in §72.2 of this chapter) following the calendar quarter of the certification testing; and

(iii) Thereafter, retesting shall be required either semiannually or annually (i.e., by the end of the second or fourth QA operating quarter following the quarter of the previous test), depending on the results of the previous test. To determine whether the next retest is due within two or four QA operating quarters, substitute the highest Hg concentration from the current test or 0.50 :g/scm (whichever is greater) into the equation in paragraph (c)(2) of this section. If the estimated annual Hg mass emissions exceeds 144 ounces, the next test is due within two QA operating quarters. If the estimated annual Hg mass emissions is 144 ounces or less, the next test is due within four QA operating quarters.

(5) The default Hg concentration used for reporting under §75.84 shall be updated after each required retest. The updated value shall either be the highest Hg concentration measured in any of the test runs or 0.50 :g/scm, whichever is greater. The updated default value shall be applied beginning with the first unit operating hour after completion of the retest.

(6) If the unit is equipped with a flue gas desulfurization system or add-on Hg controls, the owner or operator shall record the information required under §75.58(b)(3) for each unit operating hour, to document proper operation of the emission controls. For any

operating hour in which this documentation is unavailable, the maximum potential Hg concentration, as defined in section 2.1.7 of appendix A to this part, shall be reported.

(e) For units with common stack and multiple stack exhaust configurations, the use of the monitoring methodology described in paragraphs (b) through (d) of this section this section is restricted as follows:

(1) The methodology may not be used for reporting Hg mass emissions at a common stack unless all of the units using the common stack are affected units and each individual unit is demonstrated to emit 464 ounces of Hg per year, or less, in accordance with paragraphs (c) and (d) of this section. If these conditions are met, the default Hg concentration used for reporting at the common stack shall either be the highest value obtained in any test run for any of the units serving the common stack or 0.50 :g/scm, whichever is greater.

(2) For units with multiple stack or duct configurations, Hg emission testing must be performed separately on each stack or duct, and the sum of the estimated annual Hg mass emissions from the stacks or ducts must not exceed 464 ounces of Hg per year. For reporting purposes, the default Hg concentration used for each stack or duct shall either be the highest value obtained in any

test run for that stack or 0.50 :g/scm, whichever is greater.

(3) For units with a main stack and bypass stack configuration, Hg emission testing shall be performed only on the main stack. For reporting purposes, the default Hg concentration used for the main stack shall either be the highest value obtained in any test run for that stack or 0.50 :g/scm, whichever is greater. Whenever the main stack is bypassed, the maximum potential Hg concentration, as defined in section 2.1.7 of appendix A to this part, shall be reported.

(f) At the end of each calendar year, if the cumulative annual Hg mass emissions from an affected unit have exceeded 464 ounces, then the owner shall install, certify, operate, and maintain a Hg concentration monitoring system or a sorbent trap monitoring system no later than 180 days after the end of the calendar year in which the annual Hg mass emissions exceeded 464 ounces. For common stack and multiple stack configurations, installation and certification of a Hg concentration or sorbent trap monitoring system on each stack (except for bypass stacks) is likewise required within 180 days after the end of the calendar year, if:

(1) The annual Hg mass emissions at the common stack

have exceeded 464 ounces times the number of affected units using the common stack; or

(2) The sum of the annual Hg mass emissions from all of the multiple stacks or ducts has exceeded 464 ounces; or

(3) The sum of the annual Hg mass emissions from the main and bypass stacks has exceeded 464 ounces.

(g) For an affected unit that is using a Hg concentration CAMS or a sorbent trap system under §75.81(a) to continuously monitor the Hg mass emissions, the owner or operator may switch to the methodology in §75.81(b), provided that the applicable conditions in paragraphs (c) through (f) of this section are met.

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

(a) Unit utilizing common stack with other affected unit(s). When an affected unit utilizes a common stack with one or more affected units, but no non-affected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain the monitoring systems described in §75.81(a) at the common stack, record the combined Hg mass emissions for the units exhausting to the common stack. Alternatively, if, in accordance with §75.81(e), each of the units using the common stack is demonstrated to emit less than 464 ounces of

Hg per year, the owner or operator may install, certify, operate and maintain the monitoring systems and perform the Hg emission testing described under §75.81(b). If reporting of the unit heat input rate is required, determine the hourly unit heat input rates either by:

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

(ii) Installing, certifying, operating, and maintaining a flow monitoring system and diluent monitor in the duct to the common stack from each unit; or

(2) Install, certify, operate, and maintain the monitoring systems and (if applicable) perform the Hg emission testing described in §75.81(a) or §75.81(b) in the duct to the common stack from each unit.

(b) Unit utilizing common stack with nonaffected unit(s). When one or more affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either: (1) Install, certify, operate, and maintain the monitoring systems and (if applicable) perform the Hg emission testing described in §75.81(a) or §75.81(b) in the duct to the common stack from each affected unit; or

(2) Install, certify, operate, and maintain the monitoring systems described in §75.81(a) in the common

stack; and

(i) Install, certify, operate, and maintain the monitoring systems and (if applicable) perform the Hg emission testing described in §75.81(a) or §75.81(b) in the duct to the common stack from each non-affected unit. The designated representative shall submit a petition to the permitting authority and the Administrator to allow a method of calculating and reporting the Hg mass emissions from the affected units as the difference between Hg mass emissions measured in the common stack and Hg mass emissions measured in the ducts of the non-affected units, not to be reported as an hourly value less than zero. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the Hg mass emissions from the affected units are not underestimated; or

(ii) Count the combined emissions measured at the common stack as the Hg mass emissions for the affected units, for recordkeeping and compliance purposes, in accordance with paragraph (a) of this section; or

(iii) Submit a petition to the permitting authority and the Administrator to allow use of a method for apportioning Hg mass emissions measured in the common stack to each of the units using the common stack and for reporting the Hg mass emissions. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the Hg mass emissions from the affected units are not underestimated.

(c) Unit with a main stack and a bypass stack. Whenever any portion of the flue gases from an affected unit can be routed through a bypass stack to avoid the Hg monitoring system(s) installed on the main stack, the owner and operator shall either:

(1) Install, certify, operate, and maintain the monitoring systems described in §75.81(a) on both the main stack and the bypass stack and calculate Hg mass emissions for the unit as the sum of the Hg mass emissions measured at the two stacks;

(2) Install, certify, operate, and maintain the monitoring systems described in §75.81(a) at the main stack and measure Hg mass emissions at the bypass stack using the appropriate reference methods in §75.22(b). Calculate Hg mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method

monitoring systems; or

(3) Install, certify, operate, and maintain the monitoring systems and (if applicable) perform the Hg emission testing described in §75.81(a) or §75.81(b) only on the main stack. If this option is chosen, it is not necessary to designate the exhaust configuration as a multiple stack configuration in the monitoring plan required under §75.53, since only the main stack is monitored. For each unit operating hour in which the bypass stack is used, report, as applicable, the maximum potential Hg concentration (as defined in section 2.1.7 of appendix A to this part), and the appropriate substitute data values for flow rate, CO_2 concentration, O_2 concentration , and moisture (as applicable), in accordance with the missing data procedures of §§75.31 through 75.37.

(d) *Unit with multiple stack or duct configuration.* When the flue gases from an affected unit discharge to the atmosphere through more than one stack, or when the flue gases from an affected unit utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:

(1) Install, certify, operate, and maintain the monitoring systems and (if applicable) perform the Hg

emission testing described in §75.81(a) or §75.81(b) in each of the multiple stacks and determine Hg mass emissions from the affected unit as the sum of the Hg mass emissions recorded for each stack. If another unit also exhausts flue gases into one of the monitored stacks, the owner or operator shall comply with the applicable requirements of paragraphs (a) and (b) of this section, in order to properly determine the Hg mass emissions from the units using that stack; or

(2) Install, certify, operate, and maintain the monitoring systems and (if applicable) perform the Hg emission testing described in §75.81(a) or §75.81(b) in each of the ducts that feed into the stack, and determine Hg mass emissions from the affected unit using the sum of the Hg mass emissions measured at each duct, except that where another unit also exhausts flue gases to one or more of the stacks, the owner or operator shall also comply with the applicable requirements of paragraphs (a) and (b) of this section to determine and record Hg mass emissions from the units using that stack.

<u>§75.83 Calculation of Hg mass emissions and heat input rate</u>.

The owner or operator shall calculate Hg mass emissions and heat input rate in accordance with the procedures in sections 9.1 through 9.3 of appendix F to this part.

§75.84 Recordkeeping and reporting.

(a) General recordkeeping provisions. The owner or operator of any affected unit shall maintain for each affected unit and each non-affected unit under §75.82(b)(2)(ii) a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least 3 years from the date of each record. Except for the certification data required in §75.57(a)(4) and the initial submission of the monitoring plan required in §75.57(a)(5), the data shall be collected beginning with the earlier of the date of provisional certification or the compliance deadline in §75.80(b). The certification data required in §75.57(a)(4) shall be collected beginning with the date of the first certification test performed. The file shall contain the following information:

(1) The information required in §§75.57(a)(2), (a)(4), (a)(5), (a)(6), (b), (c)(2), (g) (if applicable), (h), and (i) or (j) (as applicable). For the information in §75.57(a)(2), replace the phrase “the deadline in §75.4(a), (b) or (c)” with the phrase “the applicable certification deadline under the State or Federal Hg mass emission reduction program”;

(2) The information required in §75.58(b)(3), for units with flue gas desulfurization systems or add-on Hg emission controls;

(3) For affected units using Hg CAMS or sorbent trap monitoring systems, for each hour when the unit is operating, record the Hg mass emissions, calculated in accordance with section 9 of appendix F to this part.

(4) Heat input and Hg methodologies for the hour; and

(5) Formulas from monitoring plan for total Hg mass emissions and heat input rate (if applicable);

(b) Certification, quality assurance and quality control record provisions. The owner or operator of any affected unit shall record the applicable information in §75.59 for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.82(b)(2)(ii).

(c) Monitoring plan recordkeeping provisions.

(1) General provisions. The owner or operator of an affected unit shall prepare and maintain a monitoring plan for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.82(b)(2)(ii). The monitoring plan shall contain sufficient information on the continuous monitoring systems and the use of data derived from these systems to

demonstrate that all the unit’s Hg emissions are monitored and reported.

(2) Updates. Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system or alternative monitoring system under subpart E of this part, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan.

(3) Contents of the monitoring plan. Each monitoring plan shall contain the information in §75.53(e)(1) in electronic format and the information in §75.53(e)(2) in hardcopy format.

(d) General reporting provisions.

(1) The designated representative for an affected unit shall comply with all reporting requirements in this section and with any additional requirements set forth in an applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart.

(2) The designated representative for an affected unit shall submit the following for each affected unit or group of units monitored at a common stack and each non-affected

unit under §75.82(b)(2)(ii):

(i) Initial certification and recertification applications in accordance with §75.80(d);

(ii) Monitoring plans in accordance with paragraph (e) of this section; and

(iii) Quarterly reports in accordance with paragraph (f) of this section.

(3) Other petitions and communications. The designated representative for an affected unit shall submit petitions, correspondence, application forms, and petition-related test results in accordance with the provisions in §75.80(h).

(4) Quality assurance RATA reports. If requested by the permitting authority, the designated representative of an affected unit shall submit the quality assurance RATA report for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.82(b)(2)(ii) by the later of 45 days after completing a quality assurance RATA according to section 2.3 of appendix B to this part or 15 days of receiving the request. The designated representative shall report the hardcopy information required by §75.59(a)(9) to the permitting authority.

(5) Notifications. The designated representative for

an affected unit shall submit written notice to the permitting authority according to the provisions in §75.61 for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.82(b)(2)(ii).

(e) Monitoring plan reporting.

(1) Electronic submission. The designated representative for an affected unit shall submit to the Administrator a complete, electronic, up-to-date monitoring plan file for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.82(b)(2)(ii), as follows: no later than 45 days prior to the commencement of initial certification testing; at the time of a certification or recertification application submission; and whenever an update of the electronic monitoring plan is required, either under §75.53 or elsewhere in this part.

(2) Hardcopy submission. The designated representative of an affected unit shall submit all of the hardcopy information required under §75.53, for each affected unit or group of units monitored at a common stack and each non-affected unit under §75.82(b)(2)(ii), to the permitting authority prior to initial certification. Thereafter, the designated representative shall submit

hardcopy information only if that portion of the monitoring plan is revised. The designated representative shall submit the required hardcopy information as follows: no later than 45 days prior to the commencement of initial certification testing; with any certification or recertification application, if a hardcopy monitoring plan change is associated with the recertification event; and within 30 days of any other event with which a hardcopy monitoring plan change is associated, pursuant to §75.53(b). Electronic submittal of all monitoring plan information, including hardcopy portions, is permissible provided that a paper copy of the hardcopy portions can be furnished upon request.

(f) Quarterly reports.

(1) Electronic submission. Electronic quarterly reports shall be submitted, beginning with the calendar quarter containing the compliance date in §75.80(b), unless otherwise specified in the final rule implementing a State or Federal Hg mass emissions reduction program that adopts the requirements of this subpart. The designated representative for an affected unit shall report the data and information in this paragraph (f)(1) and the applicable compliance certification information in paragraph (f)(2) of this section to the Administrator quarterly. Each

electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Each electronic report shall include the date of report generation and the following information for each affected unit or group of units monitored at a common stack.

(i) The facility information in §75.64(a)(1); and

(ii) The information and hourly data required in paragraph (a) of this section, except for:

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

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

(C) For units with flue gas desulfurization systems or with add-on Hg emission controls, the parametric information in §75.58(b)(3);

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

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

(F) Records of flow polynomial equations and numerical values required by §75.59(a)(5)(vi);

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

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

(I) Supplementary RATA information required under §75.59(a)(7)(i) through §75.59(a)(14), as applicable, except that: the data under §75.59(a)(7)(ii)(A) through (T) and the data under §75.59(a)(7)(iii)(A) through (M) shall, as applicable, be reported for flow RATAs in which angular compensation (measurement of pitch and/or yaw angles) is used and for flow RATAs in which a site-specific wall effects adjustment factor is determined by direct measurement; and the data under §75.59(a)(7)(ii)(T) shall be reported for all flow RATAs in which a default wall effects adjustment factor is applied;

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

(iii) Ounces of Hg emitted during quarter and cumulative ounces of Hg emitted in the year-to-date (rounded to the nearest thousandth); and

(iv) Unit or stack operating hours for quarter, cumulative unit or stack operating hours for year-to-date; and

(v) Reporting period heat input (if applicable) and cumulative, year-to-date heat input.

(2) Compliance certification.

(i) The designated representative shall certify that the monitoring plan information in each quarterly electronic report (i.e., component and system identification codes, formulas, etc.) represent current operating conditions for the affected unit(s)

(ii) The designated representative shall submit and sign a compliance certification in support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit’s emissions are correctly and fully monitored. The certification shall state that:

(A) The monitoring data submitted were recorded in accordance with the applicable requirements of this part, including the quality assurance procedures and specifications; and

(B) With regard to a unit with an FGD system or with add-on Hg emission controls, that for all hours where data are substituted in accordance with §75.38(b), the add-on emission controls were operating within the range of parameters listed in the quality-assurance plan for the unit (or that quality-assured SO_2 CAMS data were available to document proper operation of the emission controls), and that the substitute values do not systematically underestimate Hg emissions.

(3) Additional reporting requirements. The designated representative shall also comply with all of the quarterly reporting requirements in §§75.64(d), (f), and (g).

34. Appendix A to part 75 is amended by revising the title of section 1.1 and revising the second sentence of section 1.1 introductory text, to read as follows:

Appendix A to Part 75 – Specifications and Test Procedures

1. Installation and Measurement Location.

1.1 Gas and Hg Monitors

* * * * * Select a representative measurement point or path for the monitor probe(s) (or for the path from the transmitter to the receiver) such that the SO_2, CO_2, O_2, and NO_x concentration monitoring system or NO_x-diluent CAMS (NO_x pollutant concentration monitor and diluent gas monitor), Hg concentration monitoring system, or sorbent trap monitoring system will pass the relative accuracy test (see section 6 of this appendix).

* * * * *

Appendix A to Part 75 [Amended]

35. Appendix A to part 75 is further amended by adding new sections 2.1.7 through 2.1.7.4 and 2.2.3, to read as follows:

2. Equipment Specifications.

* * * * *

2.1.7 Hg Monitors

Determine the appropriate span and range value(s) for each Hg pollutant concentration monitor, so that all expected Hg concentrations can be determined accurately.

2.1.7.1 Maximum Potential Concentration

(a) The maximum potential concentration depends upon the type of coal combusted in the unit. For the initial MPC determination, there are three options:

(1) Use one of the following default values: 9 :g/scm for bituminous coal; 10 :g/scm for sub-bituminous coal; 16 :g/scm for lignite, and 1 :g/scm for waste coal, i.e., anthracite culm or bituminous gob. If different coals are blended, use the highest MPC for any fuel in the blend; or

(2) You may base the MPC on the results of site-specific emission testing using the one of the Hg reference methods in §75.22, if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or

if you test upstream of these control devices. A minimum of 3 test runs are required, at the normal operating load. Use the highest total Hg concentration obtained in any of the tests as the MPC; or

(3) You may base the MPC on 720 or more hours of historical CAMS data or data from a sorbent trap monitoring system, if the unit does not have add-on Hg emission controls or a flue gas desulfurization system (or if the CAMS or sorbent trap system is located upstream of these control devices) and if the Hg CAMS or sorbent trap system has been tested for relative accuracy against one of the Hg reference methods in §75.22 and has met a relative accuracy specification of 20.0% or less.

(b) For the purposes of missing data substitution, the fuel-specific or site-specific MPC values defined in paragraph (a) of this section apply to units using sorbent trap monitoring systems.

2.1.7.2 Maximum Expected Concentration

For units with FGD systems that significantly reduce Hg emissions (including fluidized bed units that use limestone injection) and for units equipped with add-on Hg emission controls (e.g., carbon injection), determine the maximum expected Hg concentration (MEC) during normal, stable operation of the unit and emission controls. To calculate the MEC, substitute the MPC value from section 2.1.7.1 of this appendix into Equation A-2 in section 2.1.1.2 of this appendix. For units with add-on Hg emission controls, base the percent removal efficiency on design engineering calculations. For units with FGD systems, use the best available estimate of the Hg removal efficiency of the FGD system.

2.1.7.3 Span and Range Value(s)

(a) For each Hg monitor, determine a high span value, by rounding the MPC value from section 2.1.7.1 of this appendix upward to the next highest multiple of 10 :g/scm.

(b) For an affected unit equipped with an FGD system or a unit with add-on Hg emission controls, if the MEC value from section 2.1.7.2 of this appendix is less than 20 percent of the high span value from paragraph (a) of this section, and if the high span value is 20 :g/scm or greater, define a second, low span value of 10 :g/scm.

(c) If only a high span value is required, set the full-scale range of the Hg analyzer to be greater than or equal to the span value.

(d) If two span values are required, you may either:

(1) Use two separate (high and low) measurement scales, setting the range of each scale to be greater than or equal to the high or low span value, as appropriate; or

(2) Quality-assure two segments of a single measurement scale.

2.1.7.4 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a periodic evaluation of the MPC, MEC, span, and range values for each Hg monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments, with corresponding monitoring plan updates. Span and range adjustments may be required, for example, as a result of changes in the fuel supply, changes in the manner of operation of the unit, or installation or removal of emission controls. In implementing the provisions in paragraphs (a) and (b) of this section, data recorded during short-term, non-representative process operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, except that up to 90 days after the end of that quarter may be taken to implement a span adjustment if the calibration gas concentrations currently being used for calibration error tests, system integrity checks, and linearity checks are unsuitable for use with the new span value and new calibration materials must be ordered.

(a) The guidelines of section 2.1 of this appendix do not apply to Hg monitoring systems.

(b) Whenever a full-scale range exceedance occurs during a quarter and is not caused by a monitor out-of-control period, proceed as follows:

(1) For monitors with a single measurement scale, report 200 percent of the full-scale range as the hourly Hg concentration until the readings come back on-scale and if appropriate, make adjustments to the MPC, span, and range to prevent future full-scale exceedances; or

(2) For units with two separate measurement scales, if the low range is exceeded, no further action is required, provided that the high range is available and is not out-of-control or out-of-service for any reason. However, if the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if

the high-scale range is exceeded follow the procedures in paragraph (b)(1) of this section).

(c) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the Hg monitor, record and report (as applicable) the new full-scale range setting, the new MPC or MEC and calculations of the adjusted span value in an updated monitoring plan. The monitoring plan update shall be made in the quarter in which the changes become effective. In addition, record and report the adjusted span as part of the records for the daily calibration error test and linearity check specified by appendix B to this part. Whenever the span value is adjusted, use calibration gas concentrations that meet the requirements of section 5.1 of this appendix, based on the adjusted span value. When a span adjustment is so significant that the calibration gas concentrations currently being used for calibration error tests, system integrity checks and linearity checks are unsuitable for use with the new span value, then a diagnostic linearity or 3-level system integrity check using the new calibration gas concentrations must be performed and passed. Use the data validation procedures in §75.20(b)(3), beginning with the hour in which the span is changed.

2.2 Design for Quality Control Testing

* * * * *

2.2.3 Mercury Monitors.

Design and equip each mercury monitor to permit the introduction of known concentrations of elemental Hg and $HgCl_2$ separately, at a point immediately preceding the sample extraction filtration system, such that the entire measurement system can be checked. If the Hg monitor does not have a converter, the $HgCl_2$ injection capability is not required.

Appendix A to Part 75 [Amended]

36. Appendix A to part 75 is further amended by:

a. Adding a new paragraph (c) to section 3.1;

b. Adding a new paragraph (c) to section 3.2; and

c. Adding new sections 3.3.8 and 3.4.3.

The revisions and additions read as follows:

3. Performance Specifications.

3.1 Calibration Error

* * * * *

(c) The calibration error of a Hg concentration monitor shall not deviate from the reference value of either the zero or upscale calibration gas by more than 5.0 percent of the span value, as calculated using Equation A-5 of this appendix. Alternatively, if the span value is 10 :g/scm, the calibration error test results are also acceptable if the absolute value of the difference between the monitor response value and the reference value, *R-A* in Equation A-5 of this appendix, is # 1.0 :g/scm.

3.2 Linearity Check

* * * * *

(c) For Hg monitors:

(1) The error in linearity for each calibration gas concentration (low-, mid-, and high-levels) shall not exceed or deviate from the reference value by more than 10.0 percent as calculated using equation A-4 of this appendix; or

(2) The absolute value of the difference between the average of the monitor response values and the average of the reference values, *R-A* in equation A-4 of this appendix, shall be less than or equal to 1.0 :g/scm, whichever is less restrictive.

(3) For the 3-level system integrity check required under §75.20(c)(1)(vi), the system measurement error shall not exceed 5.0 percent of the span value at any of the three gas levels.

3.3 Relative Accuracy

* * * * *

3.3.8 Relative Accuracy for Hg Monitoring Systems

The relative accuracy of a Hg concentration monitoring system or a sorbent trap monitoring system shall not exceed

20.0 percent. Alternatively, for affected units where the average of the reference method measurements of Hg concentration during the relative accuracy test audit is less than 5.0 :g/scm, the test results are acceptable if the difference between the mean value of the monitor measurements and the reference method mean value does not exceed 1.0 :g/scm, in cases where the relative accuracy specification of 20.0 percent is not achieved.

3.4 Bias

* * * * *

3.4.3 Hg Monitoring Systems

Mercury concentration monitoring systems and sorbent trap monitoring systems shall not be biased low as determined by the test procedure in section 7.6 of this appendix.

* * * * *

Appendix A to Part 75 [Amended]

37. Appendix A to part 75 is further amended by revising the second sentence in the first paragraph of the introductory text of section 4 and revising the second paragraph of the introductory text of section 4, to read as follows:

<u>4. Data Acquisition and Handling Systems</u>.

* * * * * These systems also shall have the

capability of interpreting and converting the individual output signals from an SO_2 pollutant concentration monitor, a flow monitor, a CO_2 monitor, an O_2 monitor, a NO_x pollutant concentration monitor, a NO_x-diluent CAMS, a moisture monitoring system, a Hg concentration monitoring system, and a sorbent trap monitoring system, to produce a continuous readout of pollutant emission rates or pollutant mass emissions (as applicable) in the appropriate units (e.g., lb/hr, lb/MMBtu, ounces/hr, tons/hr).

Data acquisition and handling systems shall also compute and record monitor calibration error; any bias adjustments to SO_2, NO_x, and Hg pollutant concentration data, flow rate data, Hg emission rate data, or NO_x emission rate data; and all missing data procedure statistics specified in subpart D of this part.

*　*　*　*　*

Appendix A to Part 75 [Amended]

38. Appendix A to part 75 is further amended by adding new section 5.1.9, to read as follows:

<u>5. Calibration Gas</u>.

*　*　*　*　*

5.1.9 Mercury Standards. For 7-day calibration error tests of Hg concentration monitors and for daily calibration error tests of Hg monitors, either elemental Hg standards or a

NIST-traceable source of oxidized Hg may be used. For linearity checks, elemental Hg standards shall be used. For 3-level and single-point system integrity checks under §75.20(c)(1)(vi), sections 6.2(g) and 6.3.1 of this appendix, and sections 2.1.1, 2.2.1 and 2.6 of appendix B to this part, a NIST-traceable source of oxidized Hg shall be used. Alternatively, other NIST-traceable standards may be used for the required checks, subject to the approval of the Administrator.

* * * * *

Appendix A to Part 75 [Amended]

39. Appendix A to part 75 is further amended by:

a. Revising the first sentence of the introductory text to section 6.2;

b. Adding new paragraph (g) to section 6.2;

c. Revising the second sentence of section 6.3.1 and adding a new third sentence;

d. Revising the first sentence of section 6.5;

e. Revising the first sentence of section 6.5(a) and adding a new third sentence;

f. Revising the second sentence of section 6.5(c);

g. Revising section 6.5(g);

h. Revising section 6.5.1(a);

i. Revising section 6.5.1(b);

j. Adding new paragraph (c) to section 6.5.6;

k. Revising the first sentence and adding three sentences at the end of section 6.5.7(a); and

l. Revising sections 6.5.7(b) and 6.5.10.

The revisions read as follows:

6. Certification Tests and Procedures.

* * * * *

6.2 Linearity Check (General Procedures)

Check the linearity of each SO_2, NO_x, CO_2, Hg, and O_2 monitor while the unit, or group of units for a common stack, is combusting fuel at conditions of typical stack temperature and pressure; it is not necessary for the unit to be generating electricity during this test. * * * * *

* * * * *

(g) For Hg monitors, follow the guidelines in section 2.2.3 of this appendix in addition to the applicable procedures in this section 6.2 when performing the 3-level system integrity checks described in §75.20(c)(1)(vi) and section 2.6 of appendix B to this part.

6.3 7-Day Calibration Error Test

6.3.1 Gas Monitor 7-day Calibration Error Test

* * * * * In all other cases, measure the calibration error of each SO_2 monitor, each NO_x monitor, each Hg concentration monitor, and each CO_2 or O_2 monitor

while the unit is combusting fuel (but not necessarily generating electricity) once each day for 7 consecutive operating days according to the following procedures. For Hg monitors, you may perform this test using either elemental Hg standards or a NIST-traceable source of oxidized Hg. * * * * *

* * * * *

6.5 Relative Accuracy and Bias Tests (General Procedures)

Perform the required relative accuracy test audits (RATAs) as follows for each CO_2 emissions concentration monitor (including O_2 monitors used to determine CO_2 emissions concentration), each SO_2 pollutant concentration monitor, each NO_x concentration monitoring system used to determine NO_x mass emissions, each flow monitor, each NO_x-diluent CAMS, each O_2 or CO_2 diluent monitor used to calculate heat input, each Hg concentration monitoring system, each sorbent trap monitoring system, and each moisture monitoring system.

* * * * *

(a) Except as otherwise provided in this paragraph or in § 75.21(a)(5), perform each RATA while the unit (or units, if more than one unit exhausts into the flue) is combusting the fuel that is a normal primary or backup fuel for that unit (for some units, more than one type of fuel may be considered normal, e.g., a unit that combusts gas or oil on a seasonal basis). For units that co-fire fuels as the predominant mode of operation, perform the RATAs while co-firing. For Hg monitoring systems, perform the RATAs while the unit is combusting coal. When relative accuracy test audits are performed on CAMS installed on bypass stacks/ducts, use the fuel normally combusted by the unit (or units, if more than one unit exhausts into the flue) when emissions exhaust through the bypass stack/ducts.

* * * * *

(c) * * * * * For units with add-on SO_2 or NO_x controls or add-on Hg controls that operate continuously rather than seasonally, or for units that need a dual range to record high concentration “spikes” during startup conditions, the low range is considered normal. * * * * *

* * * * *

(g) For each SO_2 or CO_2 emissions concentration monitor, each flow monitor, each CO_2 or O_2 diluent monitor used to determine heat input, each NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in §75.71(a)(2), each moisture monitoring system, each NO_x-diluent CAMS, each Hg concentration monitoring system, and each sorbent trap monitoring system, calculate the relative accuracy, in accordance with section 7.3 or 7.4 of this appendix, as applicable. In addition (except for CO_2, O_2, or moisture monitors), test for bias and determine the appropriate bias adjustment factor, in accordance with sections 7.6.4 and 7.6.5 of this appendix, using the data from the relative accuracy test audits.

6.5.1 Gas and Hg Monitoring System RATAs (Special Considerations)

(a) Perform the required relative accuracy test audits for each SO_2 or CO_2 emissions concentration monitor, each CO_2 or O_2 diluent monitor used to determine heat input, each NO_x-diluent CAMS, each NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in §75.71(a)(2), each Hg concentration monitoring system, and each sorbent trap monitoring system at the normal load level or normal operating level for the unit (or combined units, if common stack), as defined in section 6.5.2.1 of this appendix. If two load levels or operating levels have been designated as normal, the RATAs may be done at either load level.

(b) For the initial certification of a gas or Hg monitoring system and for recertifications in which, in addition to a RATA, one or more other tests are required (i.e., a linearity test, cycle time test, or 7-day calibration error test), EPA recommends that the RATA not be commenced until the other required tests of the CAMS have been passed.

* * * * *

6.5.6 Reference Method Traverse Point Selection

* * * * *

(c) For Hg monitoring systems, use the same traverse points that are used for the gas monitor RATAs.

* * * * *

6.5.7 Sampling Strategy

(a) Conduct the reference method tests so they will yield results representative of the pollutant concentration, emission rate, moisture, temperature, and flue gas flow rate from the unit and can be correlated with the pollutant concentration monitor, CO_2 or O_2 monitor, flow monitor, and SO_2, Hg, or NO_x CAMS measurements. * * * * * For the RATA of a Hg CAMS using the Ontario Hydro method, or for the RATA of a sorbent trap system (irrespective of the reference method used), the time per run must be long enough to collect a sufficient mass of Hg to analyze. For the RATA of a sorbent trap monitoring system, use the same-size trap that is used for daily operation of the monitoring system. Spike the third section of each sorbent trap with elemental Hg, as described in section 7.1.2 of appendix K to this part. Install a new pair of sorbent traps prior to each test run. For each run, the sorbent trap data shall be validated according to the quality assurance criteria in section 8 of appendix K to this part.

(b) To properly correlate individual SO_2, Hg, or NO_x CAMS data (in lb/MMBtu) and volumetric flow rate data with the reference method data, annotate the beginning and end of each reference method test run (including the exact time of day) on the individual chart recorder(s) or other permanent recording device(s).

* * * * *

6.5.10 Reference Methods

The following methods from appendix A to part 60 of this chapter or their approved alternatives are the reference methods for performing relative accuracy test audits: Method 1 or 1A for siting; Method 2 or its allowable alternatives in appendix A to part 60 of this chapter (except for Methods 2B and 2E) for stack gas velocity and volumetric flow rate; Methods 3, 3A, or 3B for O_2 or CO_2; Method 4 for moisture; Methods 6, 6A, or 6C for SO_2; Methods 7, 7A, 7C, 7D, or 7E for NO_x, excluding the exception in section 5.1.2 of Method 7E; and the Ontario Hydro method or an approved instrumental method for Hg (see §75.22). When using Method 7E for measuring NO_x

concentration, total NO_x, both NO and NO_2, must be measured. Notwithstanding these requirements, Method 20 may be used as the reference method for relative accuracy test audits of NO_x monitoring systems installed on combustion turbines.

* * * * *

Appendix A to Part 75 [Amended]

40. Appendix A to part 75 is further amended by:

a. Revising the title of section 7.3 and the first sentence of the introductory text of section 7.3;

b. Revising the introductory text of section 7.6;

c. Revising the first sentence in paragraph (b) of section 7.6.5 and adding a sentence at the end of paragraph (b); and

d. Revising paragraph (f) in section 7.6.5.

The revisions and additions read as follows:

7. Calculations.

* * * * *

7.3 Relative Accuracy for SO_2 and CO_2 Emissions Concentration Monitors, O_2 Monitors, NO_x Concentration Monitoring Systems, Hg Monitoring Systems, and Flow Monitors

Analyze the relative accuracy test audit data from the reference method tests for SO_2 and CO_2 emissions concentration monitors, CO_2 or O_2 monitors used only for heat input rate determination, NO_x concentration monitoring systems used to determine NO_x mass emissions under subpart H of this part, Hg monitoring systems used to determine Hg mass emissions under subpart I of this part, and flow monitors using the following procedures. * * * * *

* * * * *

7.6 Bias Test and Adjustment Factor

Test the following relative accuracy test audit data sets for bias: SO_2 pollutant concentration monitors; flow monitors; NO_x concentration monitoring systems used to determine NO_x mass emissions, as defined in §75.71(a)(2); NO_x-diluent CAMS, Hg concentration monitoring systems, and sorbent trap monitoring systems, using the procedures outlined in sections 7.6.1 through 7.6.5 of this appendix. For multiple-load flow RATAs, perform a bias test at each load level designated as normal under section 6.5.2.1 of this appendix.

* * * * *

7.6.5 Bias Adjustment

* * * * *

(b) For single-load RATAs of SO_2 pollutant concentration monitors, NO_x concentration monitoring systems, NO_x-diluent monitoring systems, Hg concentration monitoring systems, and sorbent trap monitoring systems, and for the single-load flow RATAs required or allowed under section 6.5.2 of this appendix and sections 2.3.1.3(b) and 2.3.1.3(c) of appendix B to this part, the appropriate BAF is determined directly from the RATA results at normal load, using Equation A-12. * * * * * Similarly, for Hg concentration and sorbent trap monitoring systems, where the average Hg concentration during the RATA is < 5.0 :g/dscm, if the monitoring system meets the normal or the alternative relative accuracy specification in section 3.3.8 of this appendix but fails the bias test, the owner or operator may either use the bias adjustment factor (BAF) calculated from Equation A-12 or may use a default BAF of 1.250 for reporting purposes under this part.

* * * * *

(f) Use the bias-adjusted values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the concentration of SO_2 or Hg, the flow rate, the average NO_x emission rate, the unit heat input, and the calculated mass emissions of SO_2 and CO_2 during the quarter and calendar year, as specified in subpart G of this part. In addition, when using a NO_x concentration monitoring system and a flow monitor to calculate NO_x mass emissions under subpart H of this part, or when using a Hg concentration or sorbent trap monitoring system and a flow monitor to calculate Hg mass emissions under subpart I of this part, use bias-adjusted values for NO_x (or Hg) concentration and flow rate in the mass emission calculations and use bias-adjusted NO_x (or Hg) concentrations to compute the appropriate substitution values for NO_x (or Hg) concentration in the missing data routines under subpart D of this part.

* * * * *

41. Appendix B to part 75 is amended by adding sections 1.5 through 1.5.6, to read as follows:

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

* * * * *

1.5 Requirements for Sorbent Trap Monitoring Systems

1.5.1 Sorbent Trap Identification and Tracking

Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for tracking purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

1.5.2 Monitoring System Integrity and Data Quality

Explain the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also explain the other QA procedures used to ensure system integrity and data quality, including, but not limited to, dry gas meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in section 8 of appendix K to this part.

1.5.3 Hg Analysis.

Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps (see sections 7.2.8 and 7.2.9 in appendix K to this part). Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 10 of appendix K to this part.

1.5.4 Laboratory Certification

The QA Plan shall include documentation that the laboratory performing the analyses on the carbon sorbent traps is certified by the International Organization for Standardization (ISO) to have a proficiency that meets the requirements of ISO 17025. Alternatively, if the laboratory performs the spike recovery study described in section 10.3 of appendix K to this part and repeats that procedure annually, ISO certification is not required.

1.5.5 Data Collection Period

State, and provide the rationale for, the minimum acceptable data collection period (e.g., one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Include in the discussion such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis.

1.5.6 Relative Accuracy Test Audit Procedures

Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

Appendix B to Part 75 [Amended]

42. Appendix B to part 75 is further amended by:

a. Revising the first sentence in section 2.1.1 and adding a new second sentence;

b. Revising paragraph (a) of section 2.1.4;

c. Revising section 2.2.1;

d. Revising the first sentence of section 2.3.1.1 and adding a new second sentence to paragraph (a);

e. Revising paragraph (a) of section 2.3.1.3;

f. Revising paragraph (i) of section 2.3.2;

g. Revising section 2.3.4;

h. Adding new section 2.6;

i. Revising Figure 1;

j. Revising Figure 2;

The revisions and additions read as follows:

2. Frequency of Testing.

* * * * *

2.1.1 Calibration Error Test

Except as provided in section 2.1.1.2 of this appendix, perform the daily calibration error test of each gas monitoring system (including moisture monitoring systems consisting of wet- and dry-basis O_2 analyzers) and each Hg monitoring system according to the procedures in section 6.3.1 of appendix A to this part, and perform the daily calibration error test of each flow monitoring system according to the procedure in section 6.3.2 of appendix A to this part. For Hg monitors, the daily assessments may be made using either elemental Hg standards or a NIST-traceable source of oxidized Hg. * * * * *

* * * * *

2.1.4 Data Validation

(a) An out-of-control period occurs when the calibration error of an SO_2 or NO_x pollutant concentration monitor exceeds 5.0 percent of the span value, when the calibration error of a CO_2 or O_2 monitor (including O_2 monitors used to measure CO_2 emissions or percent moisture) exceeds 1.0 percent CO_2 or O_2, or when the calibration error of a flow monitor or a moisture sensor exceeds 6.0 percent of the span value, which is twice the applicable specification of appendix A to this part. Notwithstanding, a differential pressure-type flow monitor for which the calibration error exceeds 6.0 percent of the span value shall not be considered out-of-control if *R-A*, the absolute value of the difference between the monitor response and the reference value in Equation A-6 of appendix A to this part, is $\leq$ 0.02 inches of water. In addition, an SO_2 or NO_x monitor for which the calibration error exceeds 5.0 percent of the span value shall not be considered out-of-control if *R-A* in Equation A-6 does not exceed 5.0 ppm (for span values $\leq$ 50 ppm), or if *R-A* does not exceed 10.0 ppm (for span values > 50 ppm, but $\leq$ 200 ppm). For a Hg monitor, an out-of-control period occurs when the calibration error exceeds 5.0% of the span value. Notwithstanding, the Hg monitor shall not be considered out-of-control if *R-A* in Equation A-6 does not exceed 1.0 :g/scm. The out-of-control period begins upon failure of the calibration error test and ends upon completion of a successful calibration error test. Note, that if a failed calibration, corrective action, and successful calibration error test occur within the same hour, emission data for that hour recorded by the monitor after the successful calibration error test may be used for reporting purposes, provided that two or more valid readings are obtained as required by §75.10. A NO_x-diluent CAMS is considered out-of-control if the calibration error of either component monitor exceeds twice the applicable performance specification in appendix A to this part. Emission data shall not be reported from an out-of-control monitor.

* * * * *

2.2.1 Linearity Check

Unless a particular monitor (or monitoring range) is exempted under this paragraph or under section 6.2 of appendix A to this part, perform a linearity check, in accordance with the procedures in section 6.2 of appendix A to this part, for each primary and redundant backup SO_2, Hg, and NO_x pollutant concentration monitor and each primary and redundant backup CO_2 or O_2 monitor (including O_2 monitors used to measure CO_2 emissions or to continuously monitor moisture) at least once during each QA operating quarter, as defined in §72.2 of this chapter. For Hg monitors, perform the linearity checks using elemental Hg standards. Alternatively, you may perform 3-level system integrity checks at the same three calibration gas levels (i.e., low, mid, and high), using a NIST-traceable source of oxidized Hg. If you choose this option, the performance specification in section 3.2(c)(3) of appendix A to this part must be met at each gas level. For units using both a low and high span value, a linearity check is required only on the range(s) used to record and report emission data during the QA operating quarter. Conduct the linearity checks no less than 30 days apart, to the extent practicable. The data validation procedures in section 2.2.3(e) of this appendix shall be followed.

* * * * *

2.3.1.1 Standard RATA Frequencies

(a) Except for Hg monitoring systems and as otherwise specified in §75.21(a)(6) or (a)(7) or in section 2.3.1.2 of this appendix, perform relative accuracy test audits semiannually, i.e., once every two successive QA operating quarters (as defined in §72.2 of this chapter) for each primary and redundant backup SO_2 pollutant concentration monitor, flow monitor, CO_2 emissions concentration monitor (including O_2 monitors used to determine CO_2 emissions), CO_2 or O_2 diluent monitor used to determine heat input, moisture monitoring system, NO_x concentration monitoring system, NO_x-diluent CAMS, or SO_2-diluent CAMS. For each primary and redundant backup Hg concentration monitoring system and each sorbent trap monitoring system, RATAs shall be performed annually, i.e., once every four successive QA operating quarters (as defined in §72.2 of this chapter).

* * * * *

2.3.1.3 RATA Load (or Operating) Levels and Additional RATA Requirements

(a) For SO_2 pollutant concentration monitors, CO_2 emissions concentration monitors (including O_2 monitors used to determine CO_2 emissions), CO_2 or O_2 diluent monitors used to determine heat input, NO_x concentration monitoring systems, Hg concentration monitoring systems, sorbent trap monitoring systems, moisture monitoring systems, and NO_x-diluent monitoring systems, the required semiannual or annual RATA tests shall be done at the load level (or operating level) designated as normal under section 6.5.2.1(d) of appendix A to this part. If two load levels (or operating levels) are designated as normal, the required RATA(s) may be done at either load level (or operating level).

* * * * *

2.3.2 Data Validation

* * * * *

(i) Each time that a hands-off RATA of an SO_2 pollutant concentration monitor, a NO_x-diluent monitoring system, a NO_x concentration monitoring system, a Hg concentration monitoring system, a sorbent trap monitoring system, or a flow monitor is passed, perform a bias test in accordance with section 7.6.4 of appendix A to this part. Apply the appropriate bias adjustment factor to the reported SO_2, Hg, NO_x, or flow rate data, in accordance with section 7.6.5 of appendix A to this part.

* * * * *

2.3.4 Bias Adjustment Factor

Except as otherwise specified in section 7.6.5 of appendix A to this part, if an SO_2 pollutant concentration monitor, flow monitor, NO_x CAMS, NO_x concentration monitoring system used to calculate NO_x mass emissions, Hg concentration monitoring system, or sorbent trap monitoring system fails the bias test specified in section 7.6 of appendix A to this part, use the bias adjustment factor given in Equations A-11 and A-12 of appendix A to this part, or the allowable alternative BAF specified in section 7.6.5(b) of appendix A to this part, to adjust the monitored data.

* * * * *

2.6 System Integrity Checks for Hg Monitors

For each Hg concentration monitoring system (except for a Hg monitor that does not have a converter), perform a single-point system integrity check weekly, i.e., at least once every 168 unit or stack operating hours, using a NIST-traceable source of oxidized Hg. Perform this check using a mid- or high-level gas concentration, as defined in section 5.2 of appendix A to this part. The performance specification in section 3.2(c)(3) of appendix A to this part must be met, otherwise the monitoring system is considered out-of-control until a subsequent system integrity check is passed. This weekly check is not required if the daily calibration assessments in section 2.1.1 of this appendix are performed using a NIST-traceable source of oxidized Hg.

FIGURE 1 TO APPENDIX B OF PART 75--QUALITY ASSURANCE TEST REQUIREMENTS

Test	QA test frequency requirements*				
	Daily	Weekly	Quarterly	Semiannual	Annual
Calibration Error or System Integrity Check** (2 pt.)	T				
Interference Check (flow)	T				
Flow-to-Load Ratio			T		
Leak Check (DP flow monitors)			T		
Linearity Check or System Integrity Check** (3-point)			T		
Single-point System Integrity Check**		T			
RATA (SO_2, NO_x, CO_2, O_2, H_2O)[1]				T	
RATA (all Hg monitoring systems)					T

RATA (flow)[1,2]				**T**	

[*] “Daily” means operating days, only. “Weekly” means once every 168 unit or stack operating hours. “Quarterly” means once every QA operating quarter. “Semiannual” means once every two QA operating quarters. “Annual” means once every four QA operating quarters.

[**] The system integrity check applies only to Hg monitors with converters. The single-point weekly check is not required if daily system integrity checks are performed using a NIST-traceable source of oxidized Hg.

* * * * *

FIGURE 2 TO APPENDIX B OF PART 75 -- RELATIVE ACCURACY TEST FREQUENCY INCENTIVE SYSTEM

RATA	Semiannual[w] (percent)	Annual[w]
SO_2 or NO_x[y]	7.5% < RA # 10.0% or ± 15.0 ppm[x]	RA # 7.5% or ± 12.0 ppm[x]
SO_2-diluent	7.5% < RA # 10.0% or ± 0.030 lb/MMBtu[x]	RA # 7.5% or ±0. 025 lb/MMBtu[x]
NO_x-diluent	7.5% < RA # 10.0% or ± 0.020 lb/MMBtu[x]	RA # 7.5% or ±0. 015 lb/MMBtu[x]
Flow	7.5% < RA # 10.0% or ± 1.5 fps[x]	RA # 7.5%
CO_2 or O_2	7.5% < RA # 10.0% or ± 1.0% CO_2/O_2[x]	RA # 7.5% or ± 0.7% CO_2/O_2[x]
Hg[x]	--------	RA ≤ 20.0% or ± 1.0 :g/dscm[x]
Moisture	7.5% < RA # 10.0% or ± 1.5% H_2O[x]	RA # 7.5% or ± 1.0% H_2O[x]

[w] The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarter following the quarter in which the CAMS was last tested. Exclude calendar quarters with fewer than 168 unit operating hours (or, for common stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in determining the RATA deadline. For SO_2 monitors, QA operating quarters in which only very low sulfur fuel as defined in §72.2, is combusted may also be excluded. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more

than 8 calendar quarters after the quarter in which a RATA was last performed.

[x] The difference between monitor and reference method mean values applies to moisture monitors, CO_2, and O_2 monitors, low emitters of SO_2, NO_x, or Hg, and low flow, only. The specifications for Hg monitors also apply to sorbent trap monitoring systems.

[Y] A NO_x concentration monitoring system used to determine NO_x mass emissions under §75.71.

* * * * *

43. Appendix F to part 75 is amended by adding section 9, to read as follows:

Appendix F to Part 75 – Conversion Procedures

* * * * *

9. Procedures for Hg Mass Emissions.

9.1 Use the procedures in this section to calculate the hourly Hg mass emissions (in ounces) at each monitored location, for the affected unit or group of units that discharge through a common stack.

9.1.1 To determine the hourly Hg mass emissions when using a Hg concentration monitoring system that measures on a wet basis and a flow monitor, use the following equation:

$$M_h = K\, C_h\, Q_h\, t_h \qquad \text{(Eq. F-28)}$$

Where:

M_h = Hg mass emissions for the hour, rounded off to three decimal places (ounces).
K = Units conversion constant, 9.978 x 10^{-10} oz-scm/μg-scf

C_h = Hourly Hg concentration, wet basis, adjusted for bias if the bias-test procedures in appendix A to this part show that a bias-adjustment factor is necessary (:g/wscm).
Q_h = Hourly stack gas volumetric flow rate, adjusted for bias, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary (scfh)
t_h = Unit or stack operating time, as defined in §72.2 (hr)

9.1.2 To determine the hourly Hg mass emissions when using a Hg concentration monitoring system that measures on a dry basis or a sorbent trap monitoring system and a flow monitor, use the following equation:

$$M_h = K\, C_h\, Q_h\, t_h\, (1-B_{ws}) \qquad \text{(Eq. F-29)}$$

Where:

M_h = Hg mass emissions for the hour, rounded off to three decimal places (ounces).
K = Units conversion constant, 9.978×10^{-10} oz-scm/:g-scf
C_h = Hourly Hg concentration, dry basis, adjusted for bias if the bias-test procedures in appendix A to this part show that a bias-adjustment factor is necessary (:g/dscm). For sorbent trap systems, a single value of C_h (i.e., a flow-proportional average concentration for the data collection period), is applied to each hour in the data collection period, for a particular pair of traps.
Q_h = Hourly stack gas volumetric flow rate, adjusted for bias, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary (scfh)
B_{ws} = Moisture fraction of the stack gas, expressed as a decimal (equal to % H_2O ÷ 100)
t_h = Unit or stack operating time, as defined in

9.1.3 For units that are demonstrated under §75.81(d) to emit less than 464 ounces of Hg per year, and for which the owner or operator elects not to continuously monitor the Hg concentration, calculate the hourly Hg mass emissions using Equation F-28 in section 9.1.1 of this appendix, except that "C_h" shall be the applicable default Hg concentration from §75.81(c), (d), or (e), expressed in μg/scm. Correction for the stack gas moisture content is not required when this methodology is used.

9.2 Use the following equation to calculate quarterly and year-to-date Hg mass emissions in ounces:

$$M_{time\ period} = \sum_{h=1}^{n} M_h \qquad \text{(Eq. F-30)}$$

Where:

$M_{time\ period}$ = Hg mass emissions for the given time period i.e., quarter or year-to-date, rounded to the nearest thousandth (ounces).

M_h = Hg mass emissions for the hour, rounded to three decimal places (ounces).

n = The number of hours in the given time period (quarter or year-to-date).

9.3 If heat input rate monitoring is required, follow the applicable procedures for heat input apportionment and summation in sections 5.3, 5.6 and 5.7 of this appendix.

44. Part 75 is amended by adding Appendix K, to read

as follows:

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

1.0 Scope and Application.

This appendix specifies sampling, and analytical, and quality-assurance criteria and procedures for the performance-based monitoring of vapor-phase mercury (Hg) emissions in combustion flue gas streams, using a sorbent trap monitoring system (as defined in §72.2 of this chapter). The principle employed is continuous sampling using in-stack sorbent media coupled with analysis of the integrated samples. The performance-based approach of this appendix allows for use of various suitable sampling and analytical technologies while maintaining a specified and documented level of data quality through performance criteria. Persons using this appendix should have a thorough working knowledge of Methods 1, 2, 3, 4 and 5 in appendices A-1 through A-3 to part 60 of this chapter, as well as the determinative technique selected for analysis.

1.1 Analytes. The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg (Hg^0, CAS Number 7439-97-6) and oxidized forms of Hg, in mass concentration units of micrograms per dry standard cubic meter (:g/dscm).

1.2 Applicability. These performance criteria and procedures are applicable to monitoring of vapor-phase Hg emissions under relatively low-dust conditions (i.e., sampling in the stack after all pollution control devices), from coal-fired electric utility steam generators which are subject to subpart I of this part. Individual sample collection times can range from 30 minutes to several days in duration, depending on the Hg concentration in the stack. The monitoring system must achieve the performance criteria specified in Section 8 of this appendix and the sorbent media capture ability must not be exceeded. The sampling rate must be maintained at a constant proportion to the total stack flowrate to ensure representativeness of the sample collected. Failure to achieve certain performance criteria will result in invalid Hg emissions monitoring data.

2.0 Principle.

Known volumes of flue gas are extracted from a stack or duct through paired, in-stack, pre-spiked sorbent media traps at an appropriate nominal flow rate. Collection of Hg on the sorbent media in the stack mitigates potential loss of Hg during transport through a probe/sample line. Paired train sampling is required to determine measurement precision and verify acceptability of the measured emissions data.

The sorbent traps are recovered from the sampling system, prepared for analysis, as needed, and analyzed by any suitable determinative technique that can meet the performance criteria. A section of each sorbent trap is spiked with Hg^0 prior to sampling. This section is analyzed separately and the recovery value is used to correct the individual Hg sample for measurement bias.

3.0 Clean Handling and Contamination.

To avoid Hg contamination of the samples, special attention should be paid to cleanliness during transport, field handling, sampling, recovery, and laboratory analysis, as well as during preparation of the sorbent cartridges. Collection and analysis of blank samples (field, trip, lab) is useful in verifying the absence of contaminant Hg.

4.0 Safety.

4.1 Site hazards. Site hazards must be thoroughly considered in advance of applying these procedures/specifications in the field; advance coordination with the site is critical to understand the conditions and applicable safety policies. At a minimum, portions of the sampling system will be hot, requiring appropriate gloves, long sleeves, and caution in handling this equipment.

4.2 Laboratory safety policies. Laboratory safety policies should be in place to minimize risk of chemical exposure and to properly handle waste disposal. Personnel shall wear appropriate laboratory attire according to a Chemical Hygiene Plan established by the laboratory.

4.3 Toxicity or carcinogenicity. The toxicity or carcinogenicity of any reagents used must be considered. Depending upon the sampling and analytical technologies selected, this measurement may involve hazardous materials, operations, and equipment and this appendix does not address all of the safety problems associated with implementing this approach. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performance. Any chemical should be regarded as a potential health hazard and exposure to these compounds should be minimized. Chemists should refer to the Material Safety Data Sheet (MSDS) for each chemical used.

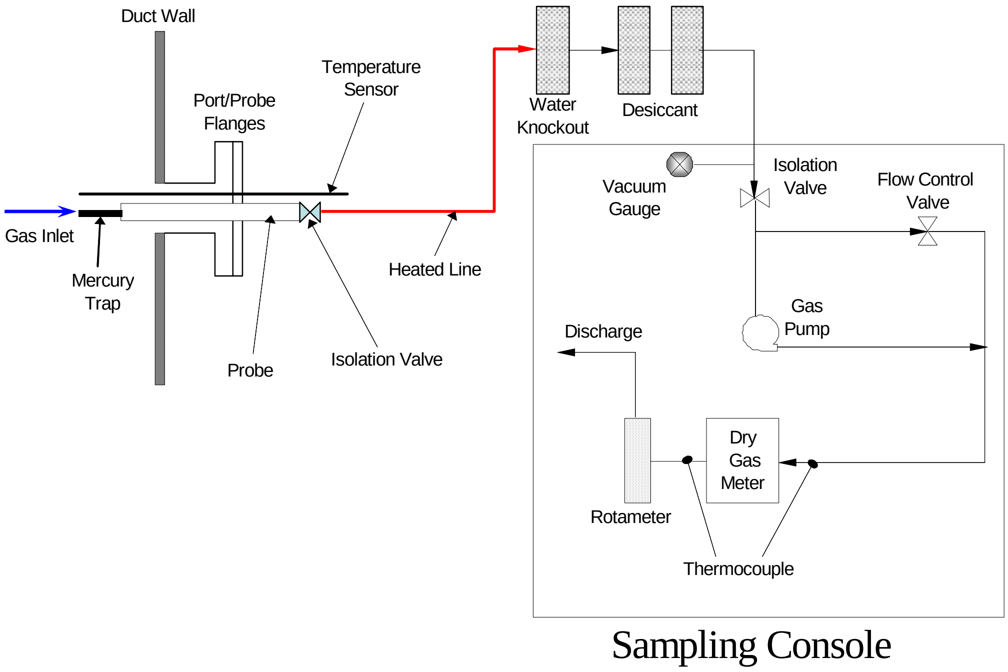
4.4 Wastes. Any wastes generated by this procedure must be disposed of according to a hazardous materials management plan that details and tracks various waste streams and disposal procedures.

5.0 Equipment and Supplies.

The following list is presented as an example of key equipment and supplies likely required to perform vapor-phase Hg monitoring using a sorbent trap monitoring system. It is recognized that additional equipment and supplies may be needed. Collection of paired samples is required. Also required are a certified stack gas volumetric flow monitor that meets the requirements of §75.10 and an acceptable means of correcting for the stack gas moisture content, i.e., either by using data from a certified continuous moisture monitoring system or by using an approved default moisture value (see §§75.11(b) and 75.12(b)).

5.1 Sorbent Trap Monitoring System. A typical sorbent trap monitoring system is shown in Figure K-1. The monitoring system shall include the following components:

Figure K-1. Typical Sorbent Trap Monitoring System



5.1.1 Sorbent Traps. The sorbent media used to collect Hg must be configured in a trap with three distinct and identical segments or sections, connected in series, that are amenable to separate analyses. Section 1 is designated for primary capture of gaseous Hg. Section 2 is designated as a backup section for determination of vapor-phase Hg breakthrough. Section 3 is designated for QA/QC purposes where this section shall be spiked with an known amount of gaseous Hg^0 prior to sampling and later analyzed to determine recovery efficiency. The sorbent media may be any collection material (e.g., carbon, chemically-treated filter, etc.) capable of quantitatively capturing and recovering for subsequent analysis, all gaseous forms of Hg for the intended application. Selection of the sorbent media shall be based on the material’s ability to achieve the performance criteria contained in Section 8 of this appendix as well as the sorbent’s vapor-phase Hg capture efficiency for the emissions matrix and the expected sampling duration at the test site. The sorbent media must be obtained from a source that can demonstrate the quality assurance and control necessary to ensure consistent reliability. The paired sorbent traps are supported on a probe (or probes) and inserted directly into the flue gas stream.

5.1.2 Sampling Probe Assembly. Each probe assembly shall have a leak-free attachment to the sorbent trap(s). Each sorbent trap must be mounted at the entrance of or within the probe such that the gas sampled enters the trap directly. Each probe/sorbent trap assembly must be heated to a temperature sufficient to prevent liquid condensation in the sorbent trap(s). Auxiliary heating is required only where the stack temperature is too low to prevent condensation. Use a calibrated thermocouple to monitor the stack temperature. A single probe capable of operating the paired sorbent traps may be used. Alternatively, individual probe/sorbent trap assemblies may be used, provided that the individual sorbent traps are co-located to ensure representative Hg monitoring and are sufficiently separated to prevent aerodynamic interference.

5.1.3 Moisture Removal Device. A robust moisture removal device or system, suitable for continuous duty (such as a Peltier cooler), shall be used to remove water vapor from the gas stream prior to entering the dry gas meter.

5.1.4 Vacuum Pump. Use a leak-tight, vacuum pump capable of operating within the candidate system’s flow range.

5.1.5 Dry Gas Meter. A dry gas meter shall be used to determine total sample volume. The meter must be sufficiently accurate to measure the total sample volume within 2 percent, must be calibrated at the selected flow rate and conditions actually encountered during sampling, and shall be equipped with a temperature sensor capable of measuring typical meter temperatures accurately to within 3°C for correcting final sample volume.

5.1.6 Sample Flow Rate Meter and Controller. Use a flow rate indicator and controller for maintaining necessary sampling flow rates.

5.1.7 Temperature Sensor. Same as Section 6.1.1.7 of Method 5 in appendix A-3 to part 60 of this chapter.

5.1.8 Barometer. Same as Section 6.1.2 of Method 5 in appendix A-3 to part 60 of this chapter.

5.1.9 Data Logger (optional). Device for recording associated and necessary ancillary information (e.g., temperatures, pressures, flow, time, etc).

5.2 Gaseous Hg^0 Sorbent Trap Spiking System. A known mass of gaseous Hg^0 must be spiked onto section 3 of each sorbent trap prior to sampling. Any approach capable of quantitatively delivering known masses of Hg^0 onto sorbent traps is acceptable. Several technologies or devices are available to meet this objective. Their practicality is a function of Hg mass spike levels. For low levels, NIST-certified or NIST-traceable gas generators or tanks may be suitable, but will likely require long preparation times. A more practical, alternative system, capable of delivering almost any mass required, makes use of NIST-certified or NIST-traceable Hg salt solutions (e.g., $Hg(NO_3)_2$). With this system, an aliquot of known volume and concentration is added to a reaction vessel containing a reducing agent (e.g., stannous chloride); the Hg salt solution is reduced to Hg^0 and purged onto section 3 of the sorbent trap using an impinger sparging system.

5.3 Sample Analysis Equipment. Any analytical system capable of quantitatively recovering and quantifying total gaseous Hg from sorbent media is acceptable provided that the analysis can meet the performance criteria in Section 8 of this procedure. Candidate recovery techniques include leaching, digestion, and thermal desorption. Candidate analytical techniques include ultraviolet atomic fluorescence (UVAF); ultraviolet atomic absorption (UVAA), with and without gold trapping; and *in situ* X-ray fluorescence (XRF) analysis.

6.0 Reagents and Standards.

Only NIST-certified or NIST-traceable calibration gas standards and reagents shall be used for the tests and procedures required under this appendix.

7.0 Sample Collection and Transport.

7.1 Pre-Test Procedures.

7.1.1 Selection of Sampling Site. Sampling site information should be obtained in accordance with Method 1 in appendix A-1 to part 60 of this chapter. Identify a monitoring location representative of source Hg emissions. Locations shown to be free of stratification through measurement traverses for gases such as SO_2 and NO_x may be one such approach. An estimation of the expected stack Hg concentration is required to establish a target sample flow rate, total gas sample volume, and the mass of Hg^0 to be spiked onto section 3 of each sorbent trap.

7.1.2 Pre-sampling Spiking of Sorbent Traps. Based on the estimated Hg concentration in the stack, the target sample rate and the target sampling duration, calculate the expected mass loading for section 1 of each sorbent trap (for an example calculation, see section 11.1 of this appendix). The pre-sampling spike to be added to section 3 of each sorbent trap shall be within ± 50 percent of the expected section 1 mass loading. Spike section 3 of each sorbent trap at this level, as described in section 5.2 of this appendix. For each sorbent trap, keep an official record of the mass of Hg^0 added to section 3. This record shall include, at a minimum, the ID number of the trap, the date and time of the spike, the name of the analyst performing the procedure, the mass of Hg^0 added to section 3 of the trap (:g), and the supporting calculations. This record shall be maintained in a format suitable for inspection and audit and shall be made available to the regulatory agencies upon request.

7.1.3 Pre-test Leak Check. Perform a leak check with the sorbent traps in place. Draw a vacuum in each sample train. Adjust the vacuum in the sample train to ~15" Hg. Using the dry gas meter, determine leak rate. The leakage rate must not exceed 4 percent of the target sampling rate. Once the leak check passes this criterion, carefully release the vacuum in the sample train then seal the sorbent trap inlet until the probe is ready for insertion into the stack or duct.

7.1.4 Determination of Flue Gas Characteristics. Determine or measure the flue gas measurement environment characteristics (gas temperature, static pressure, gas velocity, stack moisture, etc.) in order to determine ancillary requirements such as probe heating requirements (if any), initial sample rate, proportional sampling conditions, moisture management, etc.

7.2 Sample Collection.

7.2.1 Remove the plug from the end of each sorbent trap and store each plug in a clean sorbent trap storage container. Remove the stack or duct port cap and insert the probe(s). Secure the probe(s) and ensure that no leakage occurs between the duct and environment.

7.2.2 Record initial data including the sorbent trap ID, start time, starting dry gas meter readings, initial temperatures, set-points, and any other appropriate information.

7.2.3 Flow Rate Control. Set the initial sample flow rate at the target value from section 7.1.1 of this appendix. Record the initial dry gas meter reading, stack temperature, meter temperatures, etc. Then, for every operating hour during the sampling period, record the date and time, the sample flow rate, the gas meter reading, the stack temperature, the flow meter temperatures, temperatures of heated equipment such as the vacuum lines and the probes (if heated), and the sampling system vacuum readings. Also record the stack gas flow rate, as measured by the certified flow monitor, and the ratio of the stack gas flow rate to the sample flow rate. Adjust the sampling flow rate to maintain proportional sampling, i.e., keep the ratio of the stack gas flow rate to sample flow rate constant, to within ±25 percent of the reference ratio from the first hour of the data collection period (see section 11 of this appendix).

7.2.4 Stack Gas Moisture Determination. Determine stack gas moisture using a continuous moisture monitoring system, as described in §75.11(b) or §75.12(b). Alternatively, the owner or operator may use the appropriate fuel-specific moisture default value provided in §75.11 or §75.12, or a site-specific moisture default value approved by petition under §75.66.

7.2.5 Essential Operating Data. Obtain and record any essential operating data for the facility during the test period, e.g., the barometric pressure must be obtained for correcting sample volume to standard conditions. At the end of the data collection period, record the final dry gas meter reading and the final values of all other essential parameters.

7.2.6 Post Test Leak Check. When sampling is completed, turn off the sample pump, remove the probe/sorbent trap from the port and carefully re-plug the end of each sorbent trap. Perform a leak check with the sorbent traps in place, at the maximum vacuum reached during the sampling period. Use the same general approach described in section 7.1.3 of this appendix. Record the leakage rate and vacuum. The leakage rate must not exceed 4 percent of the average sampling rate for the data collection period. Following the leak check, carefully release the vacuum in the sample train.

7.2.7 Sample Recovery. Recover each sampled sorbent trap by removing it from the probe, sealing both ends. Wipe any deposited material from the outside of the sorbent trap. Place the sorbent trap into an appropriate sample storage container and store/preserve in appropriate manner.

7.2.8 Sample Preservation, Storage, and Transport. While the performance criteria of this approach provide for verification of appropriate sample handling, it is still important that the user consider, determine, and plan for suitable sample preservation, storage, transport, and holding times for these measurements. Therefore, procedures in ASTM WK223 “Guide for Packaging and Shipping Environmental Samples for Laboratory Analysis” shall be followed for all samples.

7.2.9 Sample Custody. Proper procedures and documentation for sample chain of custody are critical to ensuring data integrity. The chain of custody procedures in ASTM D4840-99 “Standard Guide for Sampling Chain-of-Custody Procedures” shall be followed for all samples (including field samples and blanks).

8.0 Quality Assurance and Quality Control.

Table K-1 summarizes the QA/QC performance criteria that are used to validate the Hg emissions data from sorbent trap monitoring systems, including the relative accuracy test audit (RATA) requirement (see §75.20(c)(9), section 6.5.7 of appendix A to this part, and section 2.3 of appendix B to this part). Except as provided in §75.15(h) and as otherwise indicated in Table K-1, failure to achieve these performance criteria will result in invalidation of Hg emissions data.

Table K-1. Quality Assurance/Quality Control Criteria for Sorbent Trap Monitoring Systems

QA/QC Test or Specification	Acceptance Criteria	Frequency	Consequences if Not Met
Pre-test leak check	≤4% of target sampling rate	Prior to sampling	Sampling shall not commence

			until the leak check is passed
Post-test leak check	≤4% of average sampling rate	After sampling	Sample invalidated**
Ratio of stack gas flow rate to sample flow rate	Maintain within ± 25% of initial ratio from first hour of data collection period	Every hour throughout data collection period	Case-by-case evaluation
Sorbent trap section 2 breakthrough	≤ 5% of Section 1 Hg mass	Every sample	Sample invalidated**
Paired sorbent trap agreement	#10% Relative Deviation (RD)	Every sample	Sample invalidated**
Spike recovery study	Average recovery between 85% and 115% for each of the 3 spike concentration levels	Prior to analyzing field samples and prior to use of new sorbent media	Field samples shall not be analyzed until the percent recovery criteria has been met
Multipoint analyzer calibration	Each analyzer reading within ± 10% of true value <u>and</u> r^2 \$0.99	On the day of analysis, before analyzing any samples	Recalibrate until successful
Analysis of independent calibration standard	Within ± 10% of true value	Following daily calibration, prior to analyzing field samples	Recalibrate and repeat independent standard analysis until successful
Spike recovery from section 3 of sorbent trap	75-125% of spike amount	Every sample	Sample invalidated**
RATA	RA ≤ 20.0%	For initial	Data from the system are

	or Mean difference ≤ 1.0 :g/dscm for low emitters	certification and annually thereafter	invalidated until a RATA is passed
Dry gas meter calibration (At 3 orifice settings initially, and 1 setting thereafter)	Calibration factor (Y) within ± 5% of average value from the initial (3-point) calibration	Prior to initial use and at least quarterly thereafter	Recalibrate the meter at three orifice settings to determine a new value of Y
Temperature sensor calibration	Absolute temperature measured by sensor within ±1.5% of a reference sensor	Prior to initial use and at least quarterly thereafter	Recalibrate. Sensor may not be used until specification is met.
Barometer calibration	Absolute pressure measured by instrument within ± 10 mm Hg of reading with a mercury barometer	Prior to initial use and at least quarterly thereafter	Recalibrate. Instrument may not be used until specification is met

[**] And data from the pair of sorbent traps are also invalidated

9.0 Calibration and Standardization.

9.1 Only NIST-certified and NIST-traceable calibration standards (i.e., calibration gases, solutions, etc.) shall be used for the spiking and analytical procedures in this appendix.

9.2 Dry Gas Meter Calibration. Prior to its initial use, perform a full calibration of the metering system at three orifice settings to determine the average dry gas meter coefficient (Y), as described in section 10.3.1 of

Method 5 in appendix A-3 to part 60 of this chapter. Thereafter, recalibrate the metering system quarterly at one intermediate orifice setting, as described in section 10.3.2 of Method 5 in appendix A-3 to part 60 of this chapter. If a quarterly recalibration shows that the value of Y has changed by more than 5 percent, repeat the full calibration of the metering system to determine a new value of Y.

9.3 Thermocouples and Other Temperature Sensors. Use the procedures and criteria in Section 10.3 of Method 2 in appendix A-1 to part 60 of this chapter to calibrate in-stack temperature sensors and thermocouples. Dial thermometers shall be calibrated against mercury-in-glass thermometers. Calibrations must be performed prior to initial use and at least quarterly thereafter. At each calibration point, the absolute temperature measured by the temperature sensor must agree to within ± 1.5 percent of the temperature measured with the reference sensor, otherwise the sensor may not continue to be used.

9.4 Barometer. Calibrate against a mercury barometer. Calibration must be performed prior to initial use and at least quarterly thereafter. At each calibration point, the absolute pressure measured by the barometer must agree to within ± 10 mm Hg of the pressure measured by the mercury barometer, otherwise the barometer may not continue to be used.

9.5 Other Sensors and Gauges. Calibrate all other sensors and gauges according to the procedures specified by the instrument manufacturer(s).

9.6 Analytical System Calibration. See section 10.1 of this appendix.

10.0 Analytical Procedures.

The analysis of the Hg samples may be conducted using any instrument or technology capable of quantifying total Hg from the sorbent media and meeting the performance criteria in section 8 of this appendix.

10.1 Analyzer System Calibration. Perform a multipoint calibration of the analyzer at three or more upscale points over the desired quantitative range (multiple calibration ranges shall be calibrated, if necessary). The field samples analyzed must fall within a calibrated, quantitative range and meet the necessary performance criteria. For samples that are suitable for aliquotting, a series of dilutions may be needed to ensure that the samples fall within a calibrated range. However, for sorbent media samples that are consumed during analysis (e.g., thermal desorption techniques), extra care must be taken to ensure that the analytical system is appropriately calibrated prior to sample analysis. The calibration curve range(s) should be determined based on the anticipated level of Hg mass on the sorbent media. Knowledge of estimated stack Hg concentrations and total sample volume may be required prior to analysis. The calibration curve for use with the various analytical techniques (e.g., UV AA, UV AF, and XRF) can be generated by directly introducing standard solutions into the analyzer or by spiking the standards onto the sorbent media and then introducing into the analyzer after preparing the sorbent/standard according to the particular analytical technique. For each calibration curve, the value of the square of the linear correlation coefficient, i.e., r^2, must be $\geq$ 0.99, and the analyzer response must be within ± 10 percent of reference value at each upscale calibration point. Calibrations must be performed on the day of the analysis, before analyzing any of the samples. Following calibration, an independently prepared standard (not from same calibration stock solution) shall be analyzed. The measured value of the independently prepared standard must be within ± 10 percent of the expected value.

10.2 Sample Preparation. Carefully separate the three sections of each sorbent trap. Combine for analysis all materials associated with each section, i.e., any supporting substrate that the sample gas passes through prior to entering a media section (e.g., glass wool, polyurethane foam, etc.) must be analyzed with that segment.

10.3 Spike Recovery Study. Before analyzing any field samples, the laboratory must demonstrate the ability to recover and quantify Hg from the sorbent media by performing the following spike recovery study for sorbent media traps spiked with elemental mercury.

Using the procedures described in sections 5.2 and 11.1 of this appendix, spike the third section of nine sorbent traps with gaseous Hg^0, i.e., three traps at each of three different mass loadings, representing the range of masses anticipated in the field samples. This will yield a 3 x 3 sample matrix. Prepare and analyze the third section of each spiked trap, using the techniques that will be used to prepare and analyze the field samples. The average recovery for each spike concentration must be between 85 and 115 percent. If multiple types of sorbent media are to be analyzed, a separate spike recovery study is required for each sorbent material. If multiple ranges are calibrated, a separate spike recovery study is required for each range.

10.4 Field Sample Analyses. Analyze the sorbent trap samples following the same procedures that were used for conducting the spike recovery study. The three sections of the sorbent trap must be analyzed separately (i.e., section 1, then section 2, then section 3). Quantify the mass of total Hg for each section based on analytical system response and the calibration curve from section 10.1 of this appendix. Determine the spike recovery from sorbent trap section 3. Pre-sampling spike recoveries must be between 75 and 125 percent. To report final Hg mass, normalize the data for sections 1 and 2 based on the sample-specific spike recovery, and add the normalized masses together.

11.0 Calculations and Data Analysis.

11.1 Calculation of Pre-sampling Spiking Level. Determine sorbent trap section 3 spiking level using estimates of the stack Hg concentration, the target sample flow rate, and the expected sample duration. First, calculate the expected Hg mass that will be collected in section 1 of the trap. The pre-sampling spike must be within ± 50 percent of this mass. Example calculation: For an estimated stack Hg concentration of 5 ug/m^3, a target sample rate of 0.30 L/min, and a sample duration of 5 days:

(0.30 L/min)(1440 min/day)(5 days)($10^{-3}$$m^3$/liter)(5:g/$m^3$)

= 10.8 :g

A pre-sampling spike of 10.8 ug ±50 percent is, therefore, appropriate.

11.2 Calculations for Flow-Proportional Sampling. For the first hour of the data collection period, determine the reference ratio of the stack gas volumetric flow rate to the sample flow rate, as follows:

$$R_{ref} = \frac{KQ_{ref}}{F_{ref}} \qquad \text{(Eq. K-1)}$$

Where:

R_{ref} = Reference ratio of hourly stack gas flow rate to hourly sample flow rate
Q_{ref} = Average stack gas volumetric flow rate for first hour of collection period, adjusted for bias, if necessary, according to section 7.6.5 of appendix A to this part, (scfh)
F_{ref} = Average sample flow rate for first hour of the collection period, in appropriate units (e.g., liters/min, cc/min, dscm/min)
K = Power of ten multiplier, to keep the value of R_{ref} between 1 and 100. The appropriate K value will depend on the selected units of measure for the sample flow rate.

Then, for each subsequent hour of the data collection period, calculate ratio of the stack gas flow rate to the sample flow rate using the equation K-2:

$$R_h = \frac{KQ_h}{F_h} \qquad \text{(Eq. K-2)}$$

Where:

R_h = Ratio of hourly stack gas flow rate to hourly sample flow rate
Q_h = Average stack gas volumetric flow rate for the hour, adjusted for bias, if necessary, according to section 7.6.5 of appendix A to this part, (scfh)
F_h = Average sample flow rate for the hour, in appropriate units (e.g., liters/min, cc/min, dscm/min)
K = Power of ten multiplier, to keep the value of R_h between 1 and 100. The appropriate K value will depend on the selected units of measure for the sample flow rate and the range of expected stack gas flow rates.

Maintain the value of R_h within ± 25 percent of R_{ref}

throughout the data collection period.

11.3 Calculation of Spike Recovery. Calculate the percent recovery of each section 3 spike, as follows:

$$\%R = \frac{M_3}{M_s} \times 100 \qquad \text{(Eq. K-3)}$$

Where:

$\%R$ = Percentage recovery of the pre-sampling spike
M_3 = Mass of Hg recovered from section 3 of the sorbent trap (:g)
M_s = Calculated Hg mass of the pre-sampling spike, from section 7.1.2 of this appendix (:g)

11.4 Calculation of Breakthrough. Calculate the percent breakthrough to the second section of the sorbent trap, as follows:

$$\%B = \frac{M_2}{M_1} \times 100 \qquad \text{(Eq. K-4)}$$

Where:

$\%B$ = Percent breakthrough
M_2 = Mass of Hg recovered from section 2 of the sorbent trap (:g)
M_1 = Mass of Hg recovered from section 1 of the sorbent trap (:g)

11.5 Normalizing Measured Hg Mass for Section 3 Spike Recoveries. Based on the results of the spike recovery in section 12.3 of this appendix, normalize the Hg mass collected in sections 1 and 2 of the sorbent trap, as follows:

$$M^* = \frac{(M_1 + M_2)\, M_s}{M_3} \qquad \text{(Eq. K-5)}$$

Where:

M^* = Normalized total mass of Hg recovered from sections 1 and of the sorbent trap (:g)
M_1 = Mass of Hg recovered from section 1 of the sorbent trap, unadjusted (:g)
M_2 = Mass of Hg recovered from section 2 of the sorbent trap, unadjusted (:g)
M_s = Calculated Hg mass of the pre-sampling spike, from section 7.1.2 of this appendix (:g)
M_3 = Mass of Hg recovered from section 3 of the sorbent trap (:g)

11.6 Calculation of Hg Concentration. Calculate the Hg concentration for each sorbent trap, using the following equation:

$$C = \frac{M^*}{V_t} \qquad \text{(Eq. K-6)}$$

Where:

C = Concentration of Hg for the collection period (:g/dscm)
M^* = Normalized total mass of Hg recovered from sections 1 and 2 of the sorbent trap (:g)
V_t = Total volume of dry gas metered during the collection period (dscm). For the purposes of this appendix, standard temperature and pressure are defined as 20^{B} C and 760 mm Hg, respectively.

11.7 Calculation of Paired Trap Agreement. Calculate the relative deviation (RD) between the Hg concentrations measured with the paired sorbent traps:

$$RD = \frac{*C_a - C_b*}{C_a + C_b} \times 100 \qquad \text{(Eq. K-7)}$$

Where:

RD = Relative deviation between the Hg concentrations from traps “a” and “b” (percent)
C_a = Concentration of Hg for the collection period, for sorbent trap “a” (:g/dscm)
C_b = Concentration of Hg for the collection period, for sorbent trap “b” (:g/dscm)

11.8 Calculation of Hg Mass Emissions. To calculate Hg mass emissions, follow the procedures in section 9.1.2 of appendix F to this part. Use the average of the two Hg concentrations from the paired traps in the calculations, except as provided in §75.15(h).

12.0 Method Performance.

These monitoring criteria and procedures have been applied to coal-fired utility boilers (including units with post-combustion emission controls), having vapor-phase Hg concentrations ranging from 0.03 :g/dscm to 100 :g/dscm.