WEST VIRGINIA
SECRETARY OF STATE
BETTY IRELAND
ADMINISTRATIVE LAW DIVISION

Form #1

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OFFICE WEST VIRGINIA SECRETARY OF STATE

NOTICE OF A PUBLIC HEARING ON A PROPOSED RULE

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

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

AMENDMENT TO AN EXISTING RULE: YES X NO ____

IF YES, SERIES NUMBER OF RULE BEING AMENDED: 16

TITLE OF RULE BEING AMENDED: Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60

IF NO, SERIES NUMBER OF RULE BEING PROPOSED: ____

TITLE OF RULE BEING PROPOSED: ____

DATE OF PUBLIC HEARING: July 18, 2005 TIME: 6:00 p.m.

LOCATION OF PUBLIC HEARING: West Virginia Department of Environmental Protection
Cooper's Rock Conference Room
601 57th Street, S.E.
Charleston, WV 25304

COMMENTS LIMITED TO: ORAL ____, WRITTEN ____, BOTH X

COMMENTS MAY ALSO BE MAILED TO THE FOLLOWING ADDRESS:

John A. Benedict, Director
WV Department of Environmental Protection
Division of Air Quality
601 57th Street, S.E.
Charleston, WV 25304

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

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

ATTACH A **BRIEF** SUMMARY OF YOUR PROPOSAL

Stephanie R. Timmermeyer

Authorized Signature

Stephanie R. Timmermeyer, Director

$15.60

DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF AIR QUALITY

BRIEFING DOCUMENT

Rule Title: 45CSR16 - "Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60"

A. AUTHORITY: W.Va. Code §22-5-4.

B. SUMMARY OF RULE:

This rule establishes and adopts national standards of performance for new stationary sources and other regulatory requirements promulgated by the United States Environmental Protection Agency (U.S. EPA) pursuant to section 111(b) of the federal Clean Air Act, as amended (CAA). This rule codifies general procedures and criteria to implement standards of performance for new stationary sources set forth in 40 CFR Part 60. The rule incorporates by reference New Source Performance Standards (NSPS) promulgated as of June 1, 2005. The rule also adopts associated appendices, reference methods, performance specifications and other test methods which are appended to such standards. Any person who constructs, modifies, reconstructs or operates an affected facility after the effective date of any NSPS under 40 CFR Part 60 must comply with the applicable NSPS and this rule.

This revised rule incorporates by reference the following new or revised NSPS standards promulgated as of July 1, 2005: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units; Stationary Gas Turbines; Steel Plants; and New and Existing Stationary Sources: Electric Utility Steam Generating Units (CAMR).

C. STATEMENT OF CIRCUMSTANCES WHICH REQUIRE RULE:

As set forth in 40 CFR §60.4(b), Section 111(c) of the CAA directs the U.S. EPA Administrator to delegate to each State the authority to implement and enforce standards of performance for new stationary sources. Promulgation of this rule will enable the State to continue to be the primary enforcement authority for NSPS promulgated by U.S. EPA. Promulgation of this rule by the Legislature is necessary for the State to fulfill its responsibilities under the CAA, as amended. Revisions to the rule include annual incorporation by reference updates, general language clarification and updated exclusions.

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

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

E. CONSTITUTIONAL TAKINGS DETERMINATION:

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

F. CONSULTATION WITH THE ENVIRONMENTAL PROTECTION ADVISORY COUNCIL:

At its June 8, 2005 meeting, the Environmental Protection Advisory Council reviewed and discussed this proposed rule. The Council's comments are contained in the attached minutes.

West Virginia Department of Environmental Protection

ADVISORY COUNCIL MEETING MINUTES

Wednesday - June 8, 2005
601 57th Street, SE, Charleston, WV
Dolly Sods Conference Room – 1st Floor

ATTENDEES:

Advisory Council Members:
Larry Harris
Jackie Hallinan
Rick Roberts
Lisa Dooley
Bill Raney
Karen Price

DEP:
Stephanie R. Timmermeyer, Cabinet Secretary
Karen G. Watson, Assistant General Counsel
Ken Ellison, Director - Division of Land Restoration
Lisa McClung, Director – Division of Water and Waste Management
John Benedict, Director – Division of Air Quality
Mike Zeto, WVDEP
Charlie Sturey, WVDEP
Jessica Greathouse, Chief Communication Officer – WVDEP – Public Information Office
James Martin, Chief, WVDEP - Office of Oil & Gas
Brett Loflin, WV Oil and Gas Conservation Commission
Dave Bassage- WVDEP
Greg Adolpson – WVDEP
Jim Mason – WVDEP
Fred Durham – WVDEP
Jim Mason – WVDEP
Mike Johnson – WVDEP

VISITORS:

Linda Tennant, Spilman, Thomas, Battle
Don Garvin – WVEC
Bob Asplund - Dominion

Karen Watson, WVDEP – Assistant General Counsel, called the meeting to order at 10:00 a.m.

Proposed rules for the 2006 legislative session are as follows:

- **45CSR1 "Control and Reduction of Nitrogen Oxides from Non-Electric Generating Units as a Means to Mitigate Transport of Ozone Precursors"**

  This rule partially fulfills the State's obligations in response to U.S. EPA's final rule, *Findings of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group region for Purposes of Reducing Regional Transport of Ozone* 27 Oct 1998, herein referred to as the *NO_x SIP Call*). Essentially, the federal rule requires that large emitters of Nitrogen Oxides (NO_x) significantly reduce emissions and constrains them to set budgets, starting in 2004 and maintaining them thereafter. Flexibility is built in through market-based "cap and trade" provisions which allow sources to buy/sell NO_x emission allowances from /to other program participants. For example, a source which has emitted NO_x in excess of its NO_x allowance allocation may purchase NO_x allowances under the federal NO_x Budget Trading Program to obtain the needed NO_x emission allowances to cover its actual NO_x emissions during an ozone season. Conversely, a source which emits fewer tons of NO_x than its NO_x allowance allocation may either bank or sell (trade) the excess NO_x allowances to another sources which needs them to cover its excess NO_x emissions.

  45CSR1 applies to large fossil fuel-fired stationary sources (large industrial boilers) with heat inputs greater than 250 mmBtu/hr. The Department of Environmental Protection, Division of Air Quality (DAQ) addresses Electric Generation Units (EGUs) in a separate rulemaking, 45CSR26. 45CSR1 also applies to large cement kilns and internal combustion engines which emitted more than one ton per day of NO_x from May 1 through September 30, 1995, although these sources are not subject to the NO_x Budget Trading Program.

  Comments:

  How will this relate to the new rule 40?

  Rule 40 will repeal Rule 1 in 2009.

  Are these kinds of trading effective in lowering NO_x emission?

  Yes, West Virginia has dropped from one of the highest to one of the lowest states.

  If one is testing, how do you see which sources account for improvement?

  Have CEMS on stacks so we can analyze data.

- **45CSR15 – "Emission Standards for Hazardous Air Pollutants Pursuant to 40CFR Part 61"**

  This rule establishes and adopts national emission standards for hazardous air pollutant (NESHAPO) and other regulatory requirements promulgated by the United States Environmental Protection Agency (USEPA) pursuant to 40CFR part 61 and section 112 of the federal clean Air Act, as amended (CAA). This rule codifies general procedures and

criteria to implement emission standards for stationary sources that emit (or have the potential to emit) one or more to the eight substances listed as hazardous air pollutants in 40 CFR §61.01(a). The rule incorporated by reference the NESHAP standards of 40 CFR Parts 61 and 65 (consolidated Federal Air Rule), to the extent referenced in 40CFR part 61, promulgated as of June 1, 2005. The rule also adopts associated appendices, reference methods, performance specifications and other test methods which are appended to these standards and contained in 40 CSR parts 61 and 65. Any person who constructs, reconstructs, modifies or operates any source subject to the provisions of 40 CFR Part 61 must comply with the applicable NESHAPS and this rule.

45CSR15, in conjunction with 45CSR34, establishes general provisions for emission standards for hazardous air pollutants (NESHAP) and other regulatory requirements promulgated by USEPA pursuant to section 112 of the federal Clean Air Act, as amended. 45CSR34 incorporates hazardous air pollutant standards codified by USEPA under 40CFR part 63 whereas 45CSR15, incorporates hazardous air pollutant standards promulgated by USEPA under 40 CFR Part 61.

This revised rule incorporates by reference the following new or revised NESHAP standards promulgated as of June 1, 2005: National Emission Standards for Hazardous Air Pollutants for Asbestos.

No Comments

- **45CSR16 – "Standards of Performance for New Stationary Sources Pursuant to 40CFR Part 60"**

This rule establishes and adopts national standards of performance for new stationary sources and other regulatory requirements promulgated by the United States Environmental Protection Agency (USEPA) pursuant to section 111(b) of the federal Clean Air Act, as amended (CAA). This rule codifies general procedures and criteria to implement standards of performance for new stationary sources set forth in 40 CFR Part 60. The rule incorporates by reference New Sources Performance Standards (NSPS) promulgated as of June 1, 2005. The rule also adopts associated appendices, reference methods, performance specifications and other test methods which are appended to such standards. Any person who constructs, modifies, reconstructs or operates an affected facility after the effective date of any NSPS under 40 CFR Part 60 must comply with the applicable NSPS and this rule.

This revised rule incorporates by reference the following new or revised NSPS standards promulgated as of July 1, 2005: Standards of performance for Industrial-Commercial-Institutional Steam Generating units; Stationary Gas Turbines: Steel Plants; and new and Existing Stationary Sources: Electric Utility Steam Generating Units (CAMR).

No Comments

- **45CSR25 – "To Prevent and Control Air Pollution from Hazardous Waste Treatment Storage or Disposal Facilities."**

  This rule establishes and adopts national standards of performance for new stationary sources and other regulatory requirements promulgated by the United States Environmental Protection Agency (USEPA) pursuant to the Resource Conservation and Recovery Act, as amended (RCRA). This rule codifies general procedures and criteria to implement emission standards set forth in the Code of Federal Regulations as listed in Table 25-A of the rule. The rule also adopts associated appendices, reference methods, performance specifications and other test methods, which are appended to these standards. Any person, who constructs, reconstructs, modifies or operates any hazardous waste treatment, storage, or disposal facility must comply with the West Virginia Hazardous Waste management Program, the codified federal emission standards, and this rule.

  45CSR25 establishes a program of regulation over the treatment, storage, and disposal of hazardous wastes in order to achieve and maintain such levels of air quality as will protect the public health and safety and the environment from the effects of improper, inadequate, or unsound treatment, storage, or disposal of hazardous wastes.

  This revised rule incorporates by reference the following provisions of 40 CFR Part 262 promulgated as of June 1, 2005: National Environmental Performance Track Program.

  Comments:

  What does the term "constituents" mean and how does one decide whether a source has prevented emissions that would cause harm under section 1.1.b of the rule?

  > *Look at the definition of "hazardous waste" and prevention language is meant to set forth overall purpose of the rule.*

  Does the agency consult with DHHR or other public health officials?

  > *No, the agency uses a risk-based approach and has a toxicologist employed. It also looks to EPA.*

- **45CSR33 – "Acid Rain Provisions and Permits"**

  This rule establishes and adopts the general provisions and operating permit program requirements for affected sources under the Acid Rain Program promulgated by the4 United States Environmental Protection Agency (USEPA) undertitle IV of the Clean Air Act, as amended (CAA). The rule also adopts associated appendices, reference methods, performance specifications and other test methods which are appended to these provisions. Under the Acid Rain Program and 45CSR33, no person may construct, modify, or operate or

cause to be constructed, modified, or operated, an Acid Rain Source in violation of 40CFR Parts 72 through 77.
Title IV of the CAA requires each state to implement an operating permit system conforming to Title IV and Title V of the CAA, as amended. 45CSR33 incorporates by reference the federal counterpart regulation 40 CFR Parts 72 through 77. USEPA approved West Virginia's Acid Rain Program with its approval of the state's Title V Operating Permit Program on December 15, 1995.

This revised rule incorporates by reference the following revisions to 40CFR Parts 72 through 77 promulgated as of June 1, 2005: Permits Regulation, Sulfur Dioxide Allowance System, Sulfur Dioxide Opt-Ins, continuous Emission Monitoring, Excess Emissions (CAIR & CAMR).

No Comments

- **45CSR34 – "Emission Standards for Hazardous Air Pollutants For Source Categories Pursuant to 40 CFR Part 63**

This rule establishes and adopts national emission standards for hazardous air pollutants (NESHAP) and other regulatory requirements promulgated by the United States Environmental Protection Agency (U.S. EPA) pursuant to section 112 of the federal Clean Air Act, as amended (CAA). This rule codifies general procedures and criteria to implement emission standards for stationary sources that emit, or have the potential to emit, one or more of the hazardous air pollutants set forth in section 112(b) of the CAA. The rule incorporates by reference the NESHAP standards of 40 CFR Parts 63 and 65 (Consolidated Federal Air Rule), to the extent referenced in 40 CFR Part 63, promulgated as of June 1, 2005. The rule also adopts associated appendices, reference methods, performance specifications and other test methods which are appended to these standards and contained in 40 CFR Parts 63 and 65. Any person who constructs, reconstructs, modifies or operates any source subject to the provisions of 40 CFR Part 63 must comply with the applicable NESHAPS and this rule.

45CSR34, in conjunction with 45CSR15, establishes general provisions for emission standards for hazardous air pollutants and other regulatory requirements promulgated by U.S. EPA pursuant to section 112 of the federal Clean Air Act, as amended. 45CSR34 incorporates hazardous air pollutant standards codified by U.S. EPA under 40 CFR Part 63 whereas 45CSR15 incorporates hazardous air pollutant standards promulgated by U.S. EPA under 40 CFR Part 61.

This revised rule incorporates by reference the following new or revised NESHAP standards promulgated as of June 1, 2005: National Environmental Performance Track Program, National Emission Standards for Hazardous Air Pollutants for Source Categories, Chromium Emissions From Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks, Plywood & Composite Wood Products; Effluent Limitations Guidelines and Standards for Timber Products Point Source Category; List of HAPs, Lesser Quantity Designations, Source Category List, Printing, Coating & Dyeing of Fabrics and Other Textiles, Stationary Combustion Turbines, Solvent Extraction for Vegetable Oil Production, Industrial,

Commercial, Institutional Boilers and Process Heaters, Secondary Aluminum Production, Coke Ovens: Pushing, Quenching, and Battery Stacks, List of Hazardous Air Pollutants, Petition Process, Lesser Quantity Designations, Source Category List; Petition to Delist of Ethylene Glycol Monobutyl Ether, Organic Hazardous Air Pollutants from Synthetic Organic Chemical Manufacturing Industry and Other Processes Subject to the Negotiated Regulation for Equipments Leaks, Coke Ovens: Pushing, Quenching, and Battery Stacks, Leather Finishing Operations, Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, Revision of December 2000 Regulatory Finding on the Emissions of HAPs from Electric Utility Steam Generating Units & Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units from Section 112(c) List, Generic MACT; Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations, Coke Oven Batteries, Miscellaneous Coating Manufacturing, Pharmaceuticals Production, Asphalt Processing & Asphalt Roofing Manufacturing and Iron and Steel Foundries.

No Comments

- **45CSR37 – "Mercury Budget Trading Program to Reduce Mercury Emissions"**

This rule establishes the general provisions and designated representative, permitting, allowance and monitoring provisions for the Mercury (Hg) Budget Trading Program, as a means of reducing national mercury emissions, pursuant to the federal Clean Air Mercury Rule (CAMR) established under Section 111 of the Clean Air Act (CAA) and 40 CFR 60, Subpart HHHH.

This rule partially fulfills the State's obligations in response to the United States Environmental Protection Agency's (U.S. EPA) final rule, *Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units* (15 March 2005, at FR XXXXX). The federal rule establishes standards of performance for mercury (Hg) for new and existing coal-fired electric utility steam generating units (utility units). This rule establishes a mechanism by which Hg emissions from new and existing coal-fired utility units are capped at specific nation-wide levels. U.S. EPA has specified that annual Hg emission reductions be implemented in two phases. The first phase of Hg reductions starts in 2010 and the second phase begins in 2018, and continues thereafter. Flexibility is built in through market-based "cap and trade" provisions which allow sources to buy or sell Hg emission allowances from or to other program participants.

45CSR37 applies to coal-fired electric utility steam generating units that have greater than 25 MW_e generating capacity.

Comments:

How will this affect Industrial boilers?

The rule does not cover these sources.

What kind of monitoring is required?

Have to install CEMS.

What happens when there is litigation?

If court remands, we would withdraw the rule.

Does the rule apply to natural gas-fired units?

No, only coal-fired.

Does the rule establish new fees?

No.

John Benedict informed the Council of the following reductions:

Nationally

2010 – 22%
2018 – 69%

WV:

2010 – 43%
2018 – 77%

- **45CSR39 – "Control of Annual Nitrogen Oxide Emissions to Mitigate Interstate Transport of Fine Particulate Matter and Nitrogen Oxides"**

This rule establishes general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the state CAIR NO_X Annual Trading Program pursuant to the federal Clean Air Interstate Rule (CAIR) under Section 110 of the Clean Air Act (CAA), 40 CFR Part 96, Subparts AA through II, and 40 CFR §51.123 for state implementation plans as a means of mitigating interstate transport of fine particulates and nitrogen oxides (NO_X).

This rule partially fulfills the State's obligations in response to the United States Environmental Protection Agency's (U.S. EPA) final rule, *Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_X SIP Call* (12 May 2005, at FR 25162). The federal rule requires that large emitters of NO_X reduce annual emissions through the constraint of set

budgets. U.S. EPA is specifying that annual NO_X emission reductions be implemented in two phases. The first phase of NO_X reductions starts in 2009; the second phase starts in 2015, and continues thereafter. The NO_X emission reduction requirements are based on controls that are known to be highly cost effective for electric generating units. Flexibility is built in through market-based "cap and trade" provisions which allow sources to buy or sell NO_X emission allowances from or to other program participants. Reducing upwind NO_X emissions will assist downwind $PM_{2.5}$ and 8-hour ozone nonattainment areas in achieving the National Ambient Air Quality Standards (NAAQS).

45CSR39 applies to large fossil fuel-fired electric generating units that have greater than 25 MW_e generating capacity. The CAIR NO_X Ozone Season Trading Program requirements are set forth in 45CSR40.

Comments:

How will this affect industrial boilers?

It will not. It only affects electric utilities.

Is there a set-aside provision?

Yes.

Agency should consider using the money to clean up streams impacted by acid rain.

- **45CSR40 – "Control of Ozone Season Nitogen Oxide Emissions to Mitigate Interstate Transport of Ozone and Nit5rogen Oxides"**

This rule establishes the general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the state CAIR NO_X Ozone Season Trading Program pursuant to the federal Clean Air Interstate Rule (CAIR) under Section 110 of the Clean Air Act (CAA), 40 CFR Part 96, Subparts AAAA through IIII, and 40 CFR §51.123 for state implementation plans as a means of mitigating interstate transport of ozone and nitrogen oxides (NO_X).

This rule partially fulfills the State's obligations in response to the United States Environmental Protection Agency's (U.S. EPA) final rule, *Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_X SIP Call* (12 May 2005, at FR 25162). The federal rule requires that large emitters of NO_X reduce ozone season emissions through the constraint of set budgets. U.S. EPA is specifying that ozone season NO_X emission reductions be implemented in two phases. The first phase of ozone season NO_X reductions starts in 2009; the second phase starts in 2015, and continues thereafter. The NO_X emission reduction requirements are based on controls that are known to be highly cost effective for electric generating units and large industrial boilers. Flexibility is built in through market-

based "cap and trade" provisions which allow sources to buy or sell NO_X emission allowances from or to other program participants. Reducing upwind ozone season NO_X emissions will assist downwind 8-hour ozone nonattainment areas in achieving the National Ambient Air Quality Standards (NAAQS).

Because CAIR subsumes the ozone season NO_X SIP Call trading program, existing NO_X SIP Call rules 45CSR1 and 45CSR26 and their ozone season NO_X reduction provisions must be "sunsetted" by January 1, 2009. Therefore, 45CSR40 contains a repeal clause which effectively "sunsets" these rules, meeting the approvability requirement for implementing CAIR.

45CSR40 applies to large fossil fuel-fired electric generating units that have greater than 25 MW_e generating capacity and large fossil fuel-fired industrial boilers with a heat input greater than 250 mmBtu/hr. This rule also applies to affected cement kilns and internal combustion engines, by retaining the NO_X SIP Call ozone season NO_X emission reduction requirements for these sources from 45CSR1. These existing requirements do not provide for inclusion in any cap and trade program for cement kilns and internal combustion engines. The CAIR NO_X Annual Trading Program requirements are set forth in 45CSR39.

No Comments.

- **33CSR41 – "Control of Annual Sulfur Dioxide Emissions to Mitigate Interstate Transport of Fine Particulate Matter and Sulfur Dioxide"**

This rule establishes general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the state CAIR SO_2 Trading Program pursuant to the federal Clean Air Interstate Rule (CAIR) under Section 110 of the Clean Air Act (CAA), 40 CFR Part 96, Subparts AAA through III, and 40 CFR §51.124 for state implementation plans as a means of mitigating interstate transport of fine particulates and sulfur dioxide (SO_2).

This rule partially fulfills the State's obligations in response to the United States Environmental Protection Agency's (U.S. EPA) final rule, *Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_X SIP Call* (12 May 2005, at FR 25162). The federal rule requires that large emitters of SO_2 reduce annual emissions based upon the implementation of retirement ratios for SO_2 allowances allocated under the Acid Rain Program. U.S. EPA is specifying that annual SO_2 emission reductions be implemented in two phases. The first phase of SO_2 reductions starts in 2010 and requires retiring SO_2 allowances at a 2:1 ratio; the second phase starts in 2015 and requires retiring SO_2 allowances at a 2.86:1 ratio, and continues thereafter. The SO_2 emissions reductions requirements are based on controls that are known to be highly cost effective for electric generating units. Flexibility is built in through market-based "cap and trade" provisions which allow sources to buy or sell SO_2 emission allowances from or to other program participants. Reducing upwind SO_2 emissions will assist downwind $PM_{2.5}$ and 8-hour ozone nonattainment

areas in achieving the National Ambient Air Quality Standards (NAAQS).

45CSR41 applies to large fossil fuel-fired electric generating units that have greater than 25 MW_e generating capacity.

How was the fiscal note derived?

It is based on how many persons will be necessary to implement the rule.

When will these rules be filed with EPA?

September of 2006 for the CAIR rules and November 2006 for the mercury rule.

- **33CSR1 – "Solid Waste Management Rule"**

This legislative rule establishes requirements for the siting (including location standards), financial assurance, installation, establishment, construction, design, groundwater monitoring, modification, operation, permitting, closure and post-closure care of any solid waste facility that processes, recycles, composts, transfers or disposes of solid waste pursuant to W. Va. Code §22-15-1 et seq. The rule revision will clarify that the State Division of Highways is subject to an exemption from permitting for its construction/demolition wastes associated with highway construction. The rule will also clarify that the beneficial reuse of clean bituminous concrete (asphalt) is not subject to permitting requirements, just as the beneficial reuse of Portland cement is not subject to permitting.

Comments:

Has the agency worked with the Division of Highways on the rule?

Yes.

- **33-CSR20 – "Hazardous Waste Management"**

The purpose of this rule is to provide for the regulation of the generation, treatment, storage, and disposal of hazardous waste to the extent necessary for the protection of the public health and safety and the environment. The rule changes pick up two new federal regulations.

No Comments.

- **35CSR3 – "Coalbed Methane Wells Rule"**

This rule applies to coalbed methane wells. The rule changes are necessary to conform to recent statutory revisions related to spacing. The changes also address new technology allowing for the horizontal drilling of wells.

Comments:

Are operators required to sample both water quality and quantity?

Just quality.

A question was raised about the 100' and 1000' distance requirements from water wells and the agency explained how these provisions work.

A comment was made that landowners are confused by the rule's requirements and some further explanations would be helpful.

- **39CSR1 – "Rules of the Commission"**

The rule is designed to prevent waste, protect correlative rights and to conserve oil and gas in the State of West Virignia and is applicable to all activities subject to the jurisdiction of the Oil and Gas Conservation Commission. Where special field rules apply, the special field rules shall govern to the extent of any conflict. The rule changes are to clarify the agency can enter consent agreements and establish escrow accounts.

No comments.

- **60CSR8 "Environmental Excellence Program Rule"**

This legislative rule establishes the eligibility, procedures, standards and legal documents required for establishing a voluntary environmental excellence program, consisting of incentives to reward facilities that go beyond regulatory requirements.

Comments:

Will the reports that are filed be shared with the public?

Yes, they will be posted on the internet.

Will people pay the $1000 fee?

From pre-comments, most are willing to pay some amount. The administrative fund will cover the agency's operating costs.

A comment was made that there should be more programs like this, where companies are rewarded for good performance.

Lisa McClung, Director of DWWM, presented several rules under the water program that will be filed in the future. One was the concentrated animal feeding operation (CAFO) rule that was withdrawn by the agency in the 2005 session. As soon as EPA repromulgates its rule, the State will need to do so, perhaps by an emergency rule.

Then the new law transferring the authority to adopt water quality standards to the DEP was discussed. A question was raised concerning the public's involvement in the process. Ms. McClung responded that the process would be somewhat different from the agency's normal rulemaking.

Karen Watson then presented a list of bills passed by the Legislature during the 2005 regular session and signed by the Governor as follows:

1. **SB 428. Creating the Revitalization Environmental Action Plan.**

This legislation transfers the litter control and recycling programs from DNR to DEP and transfers the waste tire remediation program from DOH to DEP. The legislation was amended by the House to require the excess funds to be transferred to the state road fund rather than the solid waste reclamation and environmental response fund. SB 428 bill also incorporates the provisions of Senate Bill 42 at 22-15A-12(f) and (k). These provisions provide liability protection on waste tire remediation to bona fide purchasers of property containing waste tires.

2. **SB 603. Higher Education Bill – Brownfield Assistance Centers.**

This legislation creates a provision in W.Va. Code § 18B11-7 that authorizes Marshall University and West Virginia University to each create Brownfield Assistance Centers for the purpose of acquiring and developing property; seeking federal brownfield assistance funds; and providing assistance to municipalities and local governments for brownfields development.

Comments:

The Council discussed the funding mechanisms under the new law.

3. **HB 3354. Oil and Gas Permit Fee Increase.**

This legislation increases the permit fees for shallow wells from $250 to $400; the permit fees for deep wells from $250 to $650; and the reclamation fees for all well activity from $100 to $150. This legislation also includes some technical amendments to the statutes governing oil and gas and coal bed methane drilling and production. As introduced, the legislation increased the permit fees for coal bed methane wells from $250 to $650 but the legislation was amended by the Senate to eliminate this permit fee increase. In total, this legislation will generate approximately $350,000 for the Office of Oil and Gas.

4. **SB 406. Uniform Environmental Covenant Act.**

This legislation clarifies that environmental covenants containing affirmative obligations issued pursuant to the Voluntary Remediation and Redevelopment Act or other federal or state response actions are enforceable and perpetual; provides notice requirements for those placing environmental covenants on real property; and authorizes the department and local governments to enforce environmental covenants.

Comments:

A question was raised as to local governments.

The agency responded that they are included and have authority under the new law.

5. **HB 2723. Environmental Rules Bundle.**

This legislation consolidates the rules proposed by DEP and EQB. The DEP rules include revisions to the air, waste, water and mining programs. The EQB's rule relates to water quality standards. The EQB's rule was amended to eliminate Fill Hollow Creek in Preston County that the Board recommended to be included on the Tier 2.5 list. Tier 2.5 waters are waters of special concern and include naturally reproducing trout streams.

6. **HB 3236. Thin Seam Coal Tax Applicability.**

This legislation clarifies that the special tax on coal production and the special reclamation tax apply to coal produced from thin seams.

7. **HB 2333. Environmental Good Samaritan Act.**

This legislation protect landowners, groups and individuals who volunteer to reclaim abandoned mineral extraction lands and abate water pollution caused by abandoned mine lands from civil and environmental liability provided such activities are approved by the department and implemented in accordance with the plans approved by the department.

8. **HB 3033. Continuation of Special Reclamation Tax.**

This legislation extends the temporary special reclamation tax of seven cents for an additional eighteen months thereby maintaining the total special reclamation tax at fourteen cents per ton of coal produced. The legislation also requires the Secretary to evaluate and consider additional bonding mechanisms, such as full cost bonding and the creation of a water quality trust fund.

9. **SB 154. Beneficial Reuse of Water Treatment Plant Sludge.**

This legislation authorizes the beneficial reuse of water treatment plant sludge and requires the department to develop rules establishing criteria for the beneficial reuse of water treatment plant sludge.

10. **SB 287. Transfer of Rulemaking Authority for Water Quality Standards.**

This legislation transfers the authority to promulgate water quality standards and the authority to grant remining variances from the Environmental Quality Board to the department.

11. **SB 748. Credit for Mitigation.**

This legislation authorizes the secretary to grant credit for mitigation required by the Corps of Engineers pursuant to permit issued under Section 404 of the Clean Water Act when such mitigation satisfies mitigation required by the West Virginia Water Pollution Control Act.

12. SB 700. Creation of the Community Infrastructure Investment Program.

This legislation authorizes department to grant approval for the construction of privately financed water and sewage treatment facilities without the requirement of a certificate of need and convenience from the Public Service Commission provided that the project results in economic development and improvement of water quality. This legislation also authorizes municipal utilities and public service districts to enter into community service agreements with private developers for the purpose of constructing or expanding public utilities. This legislation also requires the secretary to promulgate emergency rules to implement the program.

Comments:

Two members expressed interest in the future rulemaking efforts and any stakeholders group.

13. HB 3356. Increasing authority of the Solid Waste Management.

This legislation requires the SWMB to conduct biannual performance reviews of county and regional solid waste authorities and grants the SWMB with the authority to supersede or exercise the powers granted to county or regional solid waste authorities that operate a solid waste facility

14. SB 455. Financing of Environmental Control Activities.

This Legislation authorizes the public service commission to review and approve the use of environmental control bonds for environmental control activities by certain qualified electric utilities.

The next meeting date was scheduled for September 15, 2005 – 1:00 p.m. – 3:00 p.m. – Trish will contact everyone with room location and agenda.

Karen Watson adjourned meeting.

APPENDIX B

FISCAL NOTE FOR PROPOSED RULES

Rule Title: 45CSR16 - "Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60"

Type of Rule: ___X__ Legislative _____Interpretive _____Procedural

Agency: Division of Air Quality

Address: 601 57th Street SE
Charleston, WV 25304

Phone Number: 926-0475 Email: tmowrer@wvdep.org

Fiscal Note Summary

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

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

Fiscal Note Detail

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

FISCAL YEAR

Effect of Proposal	2006 Increase/Decrease (use "-")	2007 Increase/Decrease (use "-")	Fiscal Year (Upon Full Implementation)
1. Estimated Total Cost	$ 0	$ 0	$ 0
Personal Services	0	0	0
Current Expenses	0	0	0
Repairs & Alterations	0	0	0
Assets	0	0	0
Equipment	0	0	0
Other	0	0	0
2. Estimated Total Revenues	0	0	0

Rule Title: 45CSR16 - "Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60"

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

Costs anticipated to be incurred in the implementation of federal rules promulgated under 40 CFR Part 60 as of June 1, 2005 are included in prior cost estimates prepared for state implementation of Title V of the Clean Air Act, as amended, under 45CSR30. Full Title V program approval was issued by the U.S. Environmental Protection Agency on November 19, 2001.

MEMORANDUM

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

Date: June 15, 2005

Signature of Agency Head or Authorized Representative

John A. Benedict, Director

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

SERIES 16
STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES PURSUANT TO 40 CFR PART 60

§45-16-1. General.

1.1. Scope. -- This rule establishes and adopts standards of performance for new stationary sources promulgated by the United States Environmental Protection Agency pursuant to section 111(b) of the federal Clean Air Act, as amended (CAA). This rule codifies general procedures and criteria to implement the standards of performance for new stationary sources set forth in 40 CFR Part 60. The Secretary hereby adopts these standards by reference. The Secretary also adopts associated reference methods, performance specifications and other test methods which are appended to these standards.

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

1.3. Filing Date. -- ~~May 20, 2005~~.

1.4. Effective Date. -- ~~June 1, 2005~~.

1.5. Incorporation By Reference. -- Federal Counterpart Regulation. The Secretary has determined that a federal counterpart rule exists, and in accordance with the Secretary's recommendation, with limited exception, this rule incorporates by reference 40 CFR Parts 60 and 65, to the extent referenced in 40 CFR Part 60, effective ~~July 1, 2004~~ June 1, 2005.

1.6. Former Rules. -- This legislative rule amends 45CSR16 "Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60" which was filed ~~April 30, 2004~~ May 20, 2005, and which became effective ~~June 1, 2004~~ June 1, 2005.

§45-16-2. Definitions.

2.1. "Administrator" means the Administrator of the United States Environmental Protection Agency or his or her authorized representative.

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

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

2.4. Other words and phrases used in this rule, unless otherwise indicated, ~~shall~~ will have the meaning ascribed to them in 40 CFR Part 60. Words and phrases not defined therein ~~shall~~ will have the meaning given to them in the federal Clean Air Act.

§45-16-3. Requirements.

3.1. No person may construct, reconstruct, modify, or operate or cause to be constructed, reconstructed, modified, or operated any source subject to the provisions of 40 CFR Part 60 which results or will result in a violation of this rule.

§45-16-4. Adoption of Standards.

4.1. Standards. -- The Secretary hereby adopts and incorporates by reference the provisions

of 40 CFR Parts 60 and 65, to the extent referenced in 40 CFR Part 60, including any reference methods, performance specifications and other test methods which are appended to these standards and contained in 40 CFR Parts 60 and 65, effective ~~July 1, 2004~~ June 1, 2005, for the purposes of implementing a program for standards of performance for new stationary sources, except as follows:

4.1.a. 40 CFR §60.9 is amended to provide that information ~~shall~~ will be available to the public in accordance with W.Va. Code §§22-5-1 et seq., 29B-1-1 et seq., and 45CSR31; and

4.1.b. Subparts B, C, Ca, Cb, Cc, Cd, Ce, Ea, Ec, WWW, BBBB, CCCC, ~~and~~ DDDD and HHHH of 40 CFR Part 60 ~~shall~~ will be excluded.

§45-16-5. Secretary.

5.1. Any and all references in 40 CFR Parts 60 and 65 to the "Administrator" are amended to be the "Secretary" except as follows:

5.1.a. where the federal regulations specifically provide that the Administrator ~~shall~~ will retain authority and not transfer ~~such~~ authority to the ~~State~~ Secretary;

5.1.b. where provisions occur which refer to:

5.1.b.1. alternate means of emission limitations;

5.1.b.2. alternate control technologies;

5.1.b.3. innovative technology waivers;

5.1.b.4. alternate test methods;

5.1.b.5. alternate monitoring methods;

5.1.b.6. waivers/adjustments to recordkeeping and reporting;

5.1.b.7. emissions averaging;

5.1.b.8. applicability determinations; or

5.1.b.9. the authority to require testing under Section 114 of the Clean Air Act, as amended; or

5.1.c. where the context of the regulation clearly requires otherwise.

§45-16-6. Permits.

6.1. Nothing contained in this adoption by reference ~~shall~~ must be construed or inferred to mean that permit requirements in accordance with applicable rules ~~shall~~ will be in any way be limited or inapplicable.

§45-16-7. Inconsistency Between Rules.

7.1. In the event of any inconsistency between this rule and any other rule of the West Virginia Department of Environmental Protection, ~~such~~ the inconsistency ~~shall~~ will be resolved by the determination of the Secretary and ~~such~~ the determination ~~shall~~ will be based upon the application of the more stringent provision, term, condition, method or rule.

§ 165.503 Security Zone; Captain of the Port Hampton Roads Zone.

(a) *Definitions.* As used in this section—

Certain dangerous cargo or *CDC* means a material defined as CDC in 33 CFR 160.204.

Designated Representative of the Captain of the Port is any U.S. Coast Guard commissioned, warrant or petty officer who has been authorized by the Captain of the Port (COTP), Hampton Roads, Virginia to act on his or her behalf.

Passenger vessel means a vessel defined as a passenger vessel in 46 CFR part 70.

(b) *Location.* All navigable waters of the Captain of the Port Hampton Roads zone (defined in 33 CFR 3.25–10) within 500 yards around a passenger vessel or vessel carrying a CDC, while the passenger vessel or vessel carrying CDC is transiting, moored or anchored.

(c) *Regulations.* (1) No vessel may approach within 500 yards of a passenger vessel or vessel carrying a CDC within the Captain of the Port Hampton Roads zone, unless traveling at the minimum speed necessary to navigate safely.

(2) Under § 165.33, no vessel or person may approach within 100 yards of a passenger vessel or vessel carrying a CDC within the Captain of the Port Hampton Roads zone, unless authorized by the COTP Hampton Roads or his or her designated representative.

(3) The COTP Hampton Roads may notify the maritime and general public by marine information broadcast of the periods during which individual security zones have been activated by providing notice in accordance with 33 CFR 165.7.

(4) A security zone in effect around a moving or anchored vessel will be enforced by a law enforcement vessel. A security zone in effect around a moored vessel will be enforced by a law enforcement agent shoreside, a law enforcement vessel waterside, or both.

(5) Persons desiring to transit the area of the security zone within 100 yards of a passenger vessel or vessel carrying a CDC must contact the COTP Hampton Roads on VHF–FM channel 16 (156.8 MHz) or telephone number (757) 668–5555 or (757) 484–8192 to seek permission to transit the area. All persons and vessels must comply with the instructions of the COTP or the COTP's designated representative.

(d) *Enforcement.* The COTP will enforce these zones and may enlist the aid and cooperation of any Federal, state, county, or municipal law enforcement agency to assist in the enforcement of the regulation.

Dated: June 28, 2004.

Robert R. O'Brien, Jr.,

Captain, U.S. Coast Guard, Captain of the Port Hampton Roads.

[FR Doc. 04–15415 Filed 7–6–04; 8:45 am]

BILLING CODE 4910–15–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[OAR–2004–0068; FRL–7782–2]

RIN 2060–AK35

Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule; amendments.

SUMMARY: New source performance standards (NSPS) limiting emissions of nitrogen oxides (NO_X) from industrial-commercial-institutional steam generating units capable of combusting more than 100 million British thermal units (Btu) per hour were proposed on June 19, 1984, and were promulgated on November 25, 1986. The standards limit NO_X emissions from the combustion of fossil fuels, as well as the combustion of fossil fuels with other fuels or wastes. The standards include provisions for facility-specific NO_X standards for steam generating units which simultaneously combust fossil fuel and chemical by-product waste under certain conditions. The amendments promulgate a facility-specific NO_X standard for a steam generating unit which simultaneously combusts fossil fuel and chemical by-product waste at the Weyerhaeuser Company facility located in New Bern, North Carolina.

DATES: The direct final rule will be effective on September 7, 2004, without further notice, unless EPA receives significant adverse written comments by August 6, 2004. If EPA receives such comments, it will publish a timely withdrawal in the **Federal Register** indicating which provisions will become effective and which provisions are being withdrawn due to adverse comment.

ADDRESSES: Submit your comments, identified by Docket ID No. OAR–2004–0068, by one of the following methods:

- Federal eRulemaking Portal: *http://www.regulations.gov*. Follow the on-line instructions for submitting comments.
- Agency Web site: *http://www.epa.gov/edocket*. EDOCKET, EPA's electronic public docket and comment system, is EPA's preferred method for receiving comments. Follow the on-line instructions for submitting comments.
- E-mail: *air-and-r-docket@epa.gov*.
- Fax: (202) 566–1741.
- Mail: EPA Docket Center, Environmental Protection Agency, Mailcode: 6102T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460. Please include a duplicate copy, if possible.
- Hand Delivery: Air and Radiation Docket, Environmental Protection Agency, 1301 Constitution Avenue, NW., Room B–108, Washington, DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

We request that a separate copy also be sent to the contact person listed below (*see* **FOR FURTHER INFORMATION CONTACT**).

Instructions: Direct your comments to Docket ID No. OAR–2004–0068. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.epa.gov/edocket*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through EDOCKET, regulations.gov, or e-mail. The EPA EDOCKET and the Federal regulations.gov Web sites are "anonymous access" systems, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through EDOCKET or regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit EDOCKET on-line or see the **Federal Register** of May 31, 2002 (67 FR 38102).

Docket: All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket.* Although listed in the index, some information is not publicly available, *i.e.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at the Air and Radiation Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. James A. Eddinger, Combustion Group, Emission Standards Division (C439–01), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541–5426; facsimile number (919) 541–5450; electronic mail address *eddinger.jim@epa.gov.*

SUPPLEMENTARY INFORMATION: *Regulated Entities.* The only regulated entity that will be affected by the direct final rule amendment is the Weyerhaeuser Company facility located in New Bern, North Carolina.

Comments. We are publishing the direct final rule without prior proposal because we view it as noncontroversial and do not anticipate adverse comments. However, in the Proposed Rules section of today's **Federal Register**, we are publishing a separate document that will serve as the proposal in the event that adverse comments are filed. If we receive any adverse comments on a specific element of the direct final rule, we will publish a timely withdrawal in the **Federal Register** informing the public which amendments will become effective and which amendments are being withdrawn due to adverse comment. We will address all public comments in a subsequent final rule based on the proposed rule. Any of the distinct amendments in the direct final rule for which we do not receive adverse comment will become effective on the date set out above. We will not institute a second comment period on the direct final rule. Any parties interested in commenting must do so at this time.

World Wide Web (WWW). In addition to being available in the docket, electronic copies of today's action will be posted on the Technology Transfer Network's (TTN) policy and guidance information page *http://www.epa.gov/ttn/caaa.* 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 section 307(b)(1) of the Clean Air Act (CAA), judicial review of the direct final rule is available only on the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by September 7, 2004. Under section 307(d)(7)(B) of the CAA, only an objection to the direct final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements that are subject to today's action may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

I. Background

The objective of the NSPS, promulgated on November 25, 1986, is to limit NO_X emissions from the combustion of fossil fuel. For steam generating units combusting by-product waste, the requirements of the NSPS vary depending on the operation of the steam generating units. During periods when only fossil fuel is combusted, the steam generating unit must comply with the NO_X emission limits in the NSPS for fossil fuel. During periods when only by-product waste is combusted, the steam generating unit may be subject to other requirements or regulations which limit NO_X emissions, but it is not subject to NO_X emission limits under the NSPS. In addition, if the steam generating unit is subject to federally enforceable permit conditions limiting the amount of fossil fuel combusted in the steam generating unit to an annual capacity factor of 10 percent or less, the steam generating unit is not subject to NO_X emission limits under the NSPS when it simultaneously combusts fossil fuel and by-product waste.

With the exception noted above, during periods when fossil fuel and by-product waste are simultaneously combusted in a steam generating unit, the unit must generally comply with NO_X emission limits under 40 CFR 60.44b(e) of the NSPS. Under 40 CFR 60.44b(e) the applicable NO_X emission limit depends on the nature of the by-product waste combusted. In some situations, however, "facility-specific" NO_X emission limits developed under 40 CFR 60.44b(f) may apply. The order for determining which NO_X emission limit applies is as follows. A steam generating unit simultaneously combusting fossil fuel and by-product waste is expected to comply with the NO_X emission limit under 40 CFR 60.44b(e); only in a few situations may NO_X emission limits developed under 40 CFR 60.44b(f) apply. An equation in 40 CFR 60.44b(e) is included to determine the NO_X emission limit applicable to a steam generating unit when it simultaneously combusts fossil fuel and by-product waste.

Only where a steam generating unit which simultaneously combusts fossil fuel and by-product waste is unable to comply with the NO_X emission limit determined under 40 CFR 60.44b(e), might a facility-specific NO_X emission limit under 40 CFR 60.44b(f) apply. That section permits a steam generating unit to petition the Administrator for a facility-specific NO_X emission limit. A facility-specific NO_X emission limit will be proposed and promulgated by the Administrator for the steam generating unit, however, only where the petition is judged to be complete. To be considered complete, a petition for a facility-specific NO_X standard under 40 CFR 60.44b(f) consists of three components. The first component is a demonstration that the steam generating unit is able to comply with the NO_X emission limit for fossil fuel when combusting fossil fuel alone. The purposes of this provision are to ensure that the steam generating unit has installed best demonstrated NO_X control technology, to identify the NO_X control technology installed, and to identify the manner in which this technology is operated to achieve compliance with the NO_X emission limit for fossil fuel.

The second component of a complete petition is a demonstration that the NO_X control technology does not enable compliance with the NO_X emission limit for fossil fuel when the steam generating unit simultaneously combusts fossil fuel with chemical by-product waste under the same conditions used to demonstrate compliance on fossil fuel alone. In addition, this component of the petition must identify what unique and specific properties of the chemical by-product waste are responsible for preventing the steam generating unit from complying with the NO_X emission limit for fossil fuel.

The third component of a complete petition consists of data and/or analysis to support a facility-specific NO_X standard for the steam generating unit when it simultaneously combusts fossil fuel and chemical by-product waste and operates the NO_X control technology in

the same manner in which it would be operated to demonstrate and maintain compliance with the NO_X emission limit for fossil fuel, if only fossil fuel were combusted. This component of the petition must identify the NO_X emission limit(s) and/or operating parameter limits, and appropriate testing, monitoring, reporting and recordkeeping requirements which will ensure operation of the NO_X control technology and minimize NO_X emissions at all times.

Upon receipt of a complete petition, the Administrator will propose a facility-specific NO_X standard for the steam generating unit when it simultaneously combusts chemical by-product waste with fossil fuel. The NO_X standard will include the NO_X emission limit(s) and/or operating parameter limit(s) to ensure operation of the NO_X control technology at all times, as well as appropriate testing, monitoring, reporting and recordkeeping requirements.

The Weyerhaeuser Company has submitted a petition for a facility-specific NO_X standard for the No. 2 Power Boiler at its kraft pulp mill in New Bern, North Carolina. The No. 2 Power Boiler combusts residual oil and a byproduct/waste gas from a foul condensate steam stripper. The foul condensate steam stripper was installed to comply with the maximum achievable control technology (MACT) standards for kraft pulping systems under 40 CFR part 63, subpart S. While the No. 2 Power Boiler complies with Subpart Db of 40 CFR part 60 while firing residual oil, the combustion of stripper off-gas along with residual fuel oil in the No. 2 Power Boiler results in a NO_X emission rate in excess of the NSPS limit for the standard. Based on a review of the Weyerhaeuser Company's petition for an alternative NO_X standard, EPA's Office of Air Quality Planning and Standards has determined the petition to be complete and an alternative facility-specific standard to be appropriate. An alternative NO_X standard is provided in the final rule amendment.

II. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

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

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

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

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

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

Pursuant to the terms of Executive Order 12866, it has been determined that the direct final rule does not constitute a "significant regulatory action" because it does not meet any of the above criteria. Consequently, this action was not submitted to OMB for review under Executive Order 12866.

B. Paperwork Reduction Act

The Office of Management and Budget approved the information collection requirements contained in the standards under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, at the time the rules were promulgated on November 25, 1986.

This action does not impose any new information collection requirements of the standards and will have no impact on the information collection estimate of project cost and hour burden made and approved by OMB during the development of the standards and guidelines. Therefore, the information collection requests have not been revised.

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 our regulations are listed in 40 CFR part 9 and 40 CFR chapter 15.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA), as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 *et seq.*, generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of the direct final rule on small entities, small entity is defined as: (1) A small business whose parent company has fewer than 100 or 1,000 employees, or fewer than 4 billion kilowatt (kW)-hr per year of electricity usage, depending on the size definition for the affected North American Industry Classification System (NAICS) code; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impacts of the direct final rule on small entities, we certify that this action will not have a significant economic impact on a substantial number of small entities. The direct final rule will not impose any requirements on small entities because it does not impose any additional regulatory requirements.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires us 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 objective of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal

governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of our regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

The EPA has determined that the direct final rule amendment contains no Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year, nor does the direct final rule significantly or uniquely impact small governments, because it contains no requirements that apply to such governments or impose obligations upon them. Thus, the requirements of sections of the UMRA do not apply to the direct final rule.

E. Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999) requires us 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" are defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

The direct final rule does not have federalism implications. It will not have new substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Today's action codifies a facility-specific NO_X standard. There are minimal, if any, impacts associated with this action. Thus, Executive Order 13132 does not apply to the direct final rule.

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

Executive Order 13175 (65 FR 67249, November 6, 2000) requires us to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." The direct final rule does not have tribal implications as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the direct final rule.

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

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

We interpret Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. The direct final rule is not subject to Executive Order 13045 because it is based on technology performance and not on health or safety risks.

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

The direct final rule is not subject to Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

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; 15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards in our regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

The direct final rule amendments do not involve technical standards. Therefore, the direct final rule is not subject to NTTAA.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing the direct final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the direct final rule in the **Federal Register**. The direct final rule is not a "major rule" as defined by 5 U.S.C. section 804(2).

List of Subjects in 40 CFR Part 60

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

Dated: June 23, 2004.

Jeffrey R. Holmstead,

Assistant Administrator.

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

PART 60—[AMENDED]

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

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

Subpart Db—[Amended]

■ 2. Section 60.49b is amended by adding paragraph (x) as follows:

§ 60.49b Reporting and recordkeeping requirements.

* * * * *

(x) Facility-specific nitrogen oxides standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the nitrogen oxides emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously

combusted, the nitrogen oxides emission limit is 215 ng/J (0.5 lb/million Btu).

(2) *Emission monitoring for nitrogen oxides.* (i) The nitrogen oxides emissions shall be determined by the compliance and performance test methods and procedures for nitrogen oxides in § 60.46b.

(ii) The monitoring of the nitrogen oxides emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

[FR Doc. 04–15204 Filed 7–6–04; 8:45 am]
BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[OPP–2004–0172; FRL–7365–7]

Propoxycarbazone-sodium; Pesticide Tolerance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes a tolerance for combined residues of propoxycarbazone-sodium and its metabolite in or on meat, meat byproducts, wheat and milk. Bayer CropScience requested this tolerance under the Federal Food, Drug, and Cosmetic Act (FFDCA), as amended by the Food Quality Protection Act of 1996 (FQPA).

DATES: This regulation is effective July 7, 2004. Objections and requests for hearings must be received on or before September 7, 2004.

ADDRESSES: To submit a written objection or hearing request follow the detailed instructions as provided in Unit VI. of the **SUPPLEMENTARY INFORMATION.** EPA has established a docket for this action under Docket ID number OPP–2004–0172. All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket.* Although listed in the index, some information is not publicly available, i.e., Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at the Public Information and Records Integrity Branch (PIRIB), Rm. 119, Crystal Mall #2, 1801 Bell Street, Arlington, VA. This docket facility is open from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The docket telephone number is (703) 305–5805.

FOR FURTHER INFORMATION CONTACT: Joanne I. Miller, Registration Division (7505C), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: (703) 305–6224; e-mail address: *miller.joanne@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. Potentially affected entities may include, but are not limited to:

- Crop production (NAICS 111), e.g., agricultural workers; greenhouse, nursery, and floriculture workers; farmers.
- Animal production (NAICS 112), e.g., cattle ranchers and farmers, dairy cattle farmers, livestock farmers.
- Food manufacturing (NAICS 311), e.g., agricultural workers; farmers; greenhouse, nursery, and floriculture workers; ranchers; pesticide applicators.
- Pesticide manufacturing (NAICS 32532), e.g., agricultural workers; commercial applicators; farmers; greenhouse, nursery, and floriculture workers; residential users.

This listing is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in this unit could also be affected. The North American Industrial Classification System (NAICS) codes have been provided to assist you and others in determining whether this action might apply to certain entities. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT.**

B. How Can I Access Electronic Copies of this Document and Other Related Information?

In addition to using EDOCKET *(http://www.epa.gov/edocket/)*, you may access this **Federal Register** document electronically through the EPA Internet under the "**Federal Register**" listings at *http://www.epa.gov/fedrgstr/.* A frequently updated electronic version of 40 CFR part 180 is available at E-CFR Beta Site Two at *http://www.gpoaccess.gov/ecfr/.* The OPPTS Harmonized Test Guidelines referenced in this document are avaiable at *http://www.epa.gpo/opptsfrs/home/guidelin.htm/.*

II. Background and Statutory Findings

In the **Federal Register** of August 21, 2002 (67 FR 54188) (FRL–7195–2), EPA issued a notice pursuant to section 408(d)(3) of FFDCA, 21 U.S.C. 346a(d)(3), announcing the filing of a pesticide petition (PP 0F6094) by Bayer Corporation, 8400 Hawthorn Road, Kansas City MO, 64120–0013. That notice included a summary of the petition prepared by Bayer Corporation, the registrant. There were no comments received in response to the notice of filing. The company name and address were subsequently changed to Bayer CropScience, P.O. Box 12014, 2 T.W. Alexander Drive, Research Triangle Park, NC 27709.

The petition requested that 40 CFR 180 be amended by establishing tolerances for residues of the herbicide, propoxycarbazone-sodium, methyl 2-[[[(4,5-dihydro-4-methyl-5-oxo-3-propoxy-1H-1,2,4-triazol-1-yl)carbonyl]amino]sulfonyl]benzoate, sodium salt and its metabolite, methyl 2-[[[(4,5-dihydro-4-methyl-5-oxo-3-(2′-hydroxy-propoxy)-1H-1,2,4-triazol-1-yl)carbonyl]amino]sulfonyl]benzoate, in or on the raw agricultural commodities (RACs) wheat forage, wheat hay, wheat straw, wheat grain, meat, and meat byproducts, (cattle, sheep, goats, horses, hogs), and milk at 1.5, 0.15, 0.05, 0.01, 0.05, and 0.002 parts per million (ppm); respectively. Bayer CropScience subsequently amended the petition by requesting that 40 CFR 180 be amended establishing tolerances for residues of the herbicide, propoxycarbazone, methyl 2-[[[(4,5-dihydro-4-methyl-5-oxo-3-propoxy-1H-1,2,4-triazol-1-yl)carbonyl]amino]sulfonyl]benzoate, sodium salt and its metabolite, methyl 2-[[[(4,5-dihydro-3-(2-hydroxypropoxy)-4-methyl-5-oxo-1H-1,2,4-triazol-1-yl)carbonyl]amino]sulfonyl]benzoate, in

Federal Register

Thursday,
July 8, 2004

Part III

Environmental Protection Agency

40 CFR Part 60
Standards of Performance for Stationary Gas Turbines; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[OAR–2002–0053, FRL–7780–6]

RIN 2060–AK35

Standards of Performance for Stationary Gas Turbines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; amendments.

SUMMARY: This action promulgates amendments to several sections of the standards of performance for stationary gas turbines in 40 CFR part 60, subpart GG. The amendments will codify several alternative testing and monitoring procedures that have routinely been approved by EPA. The amendments will also reflect changes in nitrogen oxides (NO_X) emission control technologies and turbine design since the standards were promulgated.

DATES: The final rule is effective July 8, 2004. The incorporation by reference of certain publications in the final rule is approved by the Director of the Office of the Federal Register as of July 8, 2004.

ADDRESSES: *Docket.* The EPA has established a docket for this action under Docket ID No. OAR–2002–0053. All documents in the docket are listed in EDOCKET index at *http://www.epa.gov/edocket.* Although listed in the index, some information is not publicly available, *i.e.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at the Air Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Avenue, NW, Washington, DC 20460. The public reading room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Jaime Pagan, Combustion Group, Emission Standards Division (C439–01), U.S. EPA, Research Triangle Park, North Carolina 27711; telephone number (919) 541–5340; facsimile number (919) 541–5450; electronic mail address *pagan.jaime@epa.gov.*

SUPPLEMENTARY INFORMATION: *Regulated Entities.* Entities potentially regulated by this action are those that own and operate stationary gas turbines, and are the same as the existing rule in 40 CFR part 60, subpart GG. Regulated categories and entities include:

Category	NAICS	SIC	Examples of regulated entities
Any industry using a stationary combustion turbine as defined in the final rule.	2211	4911	Electric services.
	486210	4922	Natural gas transmission.
	211111	1311	Crude petroleum and natural gas.
	211112	1321	Natural gas liquids.
	221	4931	Electric and other services, combined.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your facility is regulated by this action, you should examine the applicability criteria in § 60.330 of the final rule. If you have questions regarding the applicability of this action to a particular entity, consult the contact person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Docket. The EPA has established an official public docket for this action under Docket ID No. OAR–2002–0053. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public docket does not include Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. The official public docket is the collection of materials that is available for public viewing at the Air Docket in the EPA Docket Center, Room B108, 1301 Constitution Ave., NW., Washington, DC 20460. The EPA Docket Center 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. The telephone number for the Air Docket is (202) 566–1742. A reasonable fee may be charged for copying docket materials.

Electronic Access. You may access this **Federal Register** document electronically through the EPA Internet under the **Federal Register** listings at *http://www.epa.gov/fedrgstr/.*

An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at *http://www.epa.gov/edocket/* to view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the docket facility located above. Once in the system, select "search," then key in the appropriate docket identification number.

World Wide Web (WWW). In addition to being available in the docket, an electronic copy of the final rule is also available on the WWW through the Technology Transfer Network (TTN). Following signature, a copy of the promulgated 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 section 307(b)(1) of the Clean Air Act (CAA), judicial review of the final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by September 7, 2004. Under section 307(d)(7)(B) of the CAA, only an objection to a rule or procedure raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by the final rule may not be challenged separately in any civil or criminal proceeding brought to enforce these requirements.

Background Information Document. During the comment period, EPA received 23 comment letters on the proposal and direct final rule. A background information document (BID) ("Response to Public Comments on Proposed Standards of Performance for Stationary Gas Turbines,") containing

EPA's responses to each public comment is available in Docket ID No. OAR–2002–0053.

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

I. Background

Under section 111 of the CAA, 42 U.S.C. 7411, the EPA promulgated standards of performance for stationary gas turbines (40 CFR part 60, subpart GG). The standards were promulgated on September 10, 1979 (44 FR 52798). Since that time, many advances in the design of the NO_X emission controls used in gas turbines have occurred. Additional test methods have also been developed to measure emissions from gas turbines and the sulfur content of gaseous fuels. As a result of these advances, we have had many requests for case-by-case approvals of alternative testing and monitoring procedures for subpart GG. We are promulgating the amendments to subpart GG to codify the alternatives that have been routinely approved. Additionally, we are attempting to harmonize, where appropriate, the provisions of subpart GG with the monitoring provisions of 40 CFR part 75, the continuous emission monitoring requirements of the acid rain program under title IV of the CAA, since many existing and new gas turbines are subject to both regulations.

On April 14, 2003, we published a direct final rule (68 FR 17990) and a parallel proposal (68 FR 18003) amending the standards of performance for stationary gas turbines (40 CFR part 60, subpart GG). We stated in the preambles to the direct final rule and parallel proposal that if we received adverse comments on one or more distinct provisions of the direct final rule, we would publish a timely withdrawal of those distinct provisions in the **Federal Register**. The preamble to the direct final rule stated that the deadline for submitting public comments was May 14, 2003, and the effective date of the provisions would be May 29, 2003. The preamble to the proposal also stated that if a public hearing was requested by April 24, 2003, the hearing would be held on May 14, 2003, and the comment period would be extended until 30 days after the date of the public hearing. Since a public hearing was requested, the comment period was extended until June 13, 2003. The entire direct final rule was withdrawn in order to avoid the direct final rule becoming effective before all public comments were received.

II. Discussion of Revisions

A. Continuous Monitoring Options

Under the original provisions of subpart GG, 40 CFR part 60, any affected unit with a water injection system was required to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. These operating parameters demonstrate that a turbine continues to operate under the same performance conditions as those documented during the initial and any subsequent compliance tests, thus providing reasonable assurance of compliance with the NO_X standard. We are amending the regulation to allow the use of NO_X continuous emission monitoring systems (CEMS) to demonstrate compliance, as detailed in the following paragraphs.

Owners or operators of turbines that commenced construction, reconstruction, or modification after October 3, 1977, but before July 8, 2004, and that use water or steam injection to control NO_X emissions can continue to use the NO_X monitoring system which is currently being used, or may elect to use a NO_X CEMS. The CEMS must be installed, operated, and maintained according to the appropriate performance specification requirements in 40 CFR part 60, appendix B. Alternatively, sources may choose to use data from a NO_X CEMS that is certified according to the requirements of 40 CFR part 75. Any owners or operators of turbines constructed, reconstructed, or modified in this time period that do not use water or steam injection and that have received EPA or local permitting authority approval of an alternative monitoring strategy can continue to follow the conditions of the petition approval.

For new turbines constructed after July 8, 2004, and using water or steam injection for NO_X control, owners/operators can elect to use either the existing requirements for continuous water or steam to fuel ratio monitoring or may elect to use a CEMS to monitor NO_X. The CEMS must be installed and certified according to Performance Specifications (PS) 2 and 3 of 40 CFR part 60, appendix B. Alternatively, sources may choose to use data from a NO_X CEMS that is certified according to the requirements of 40 CFR part 75, appendix A.

Owners or operators of new turbines that commence construction after July 8, 2004, and do not use water or steam injection to control NO_X emissions can use a NO_X CEMS as an alternative to continuously monitoring fuel consumption and water or steam to fuel ratio, provided the CEMS is installed and certified according to PS 2 and 3 of 40 CFR part 60, appendix B and 40 CFR 60.13 or the requirements of 40 CFR part 75, appendix A. An acceptable alternative to installation of a NO_X CEMS is continuous parameter monitoring. If this option is chosen, owners or operators of uncontrolled diffusion flame turbines must continuously monitor at least four parameters indicative of the unit's NO_X formation characteristics. For lean premix turbines, continuous monitoring of parameters that indicate whether the turbine is operating in the lean premixed combustion mode is required. Examples of these parameters may include percentage of full load, turbine exhaust temperature, combustion reference temperature, compressor discharge pressure, fuel and air valve positions, dynamic pressure pulsations, internal guide vane position, and flame detection or flame scanner conditions. Definitions for diffusion flame turbine

and lean premix turbine consistent with those in the combustion turbine final rule have been added to the definitions section of the final rule. Parameters that indicate proper operation of the emission control device must be monitored for turbines that use selective catalytic reduction. In all cases, the acceptable values and ranges for the parameters must be established during the initial performance test for the turbine and recorded in a parameter monitoring plan, to be kept on-site.

If the option to use a NO_X CEMS is chosen, we have specified the minimum data requirements. For full operating hours, each monitor must complete at least one cycle of operation (including sampling, analyzing, and data recording) for each 15-minute quadrant of the hour. For partial unit operating hours, one valid data point must be obtained for each quadrant of the hour for which the unit is operating. A minimum of two valid data points in two different 15-minute quadrants are required for hours in which required quality assurance and maintenance activities are performed on the CEMS. This data must be reduced to hourly averages for purposes of identifying excess emissions. The data acquisition and handling system must record the hourly NO_X emissions as well as the International Organization for Standardization (ISO) standard conditions (if applicable).

In lieu of recording the ISO standard conditions, a worst case ISO correction factor can be calculated using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (H_o), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation. By using worst case parameters in this equation, the owner/operator can ensure compliance in all situations without having to continuously monitor temperature, humidity and pressure. Several case-by-case determinations performed by EPA have accepted this methodology as an alternative to continuous monitoring of atmospheric conditions.

No NO_X or oxygen (O_2) CEMS data generated using the missing data substitution procedures in 40 CFR part 75 may be used to demonstrate compliance with the subpart GG, 40 CFR part 60, emission limits. Instead, these periods of missing data are counted as monitor downtime in the excess emissions and monitoring report required under 40 CFR 60.7(c). For turbines using NO_X CEMS, we have defined excess emissions as any unit operating hour during which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit.

The 4-hour averaging period for defining excess emissions approximates the amount of time typically required to conduct a performance test of a combustion turbine using EPA Method 20. The 4-hour averaging period is relatively short compared to 24-hour and 30-day averaging times used for other types of combustion devices (*e.g.*, boilers). However, for these other combustion units, a longer averaging period is generally needed to account for variability in the NO_X emissions, particularly when solid fuels are fired. Combustion turbines typically use natural gas or diesel, which both have relatively uniform predictable NO_X emissions. Therefore, a shorter averaging time such as 4 hours is considered adequate to assess compliance. An averaging time of 1 hour was also considered, but was rejected since 4 hours more closely represents the typical duration of a combustion turbine stack test and will account for any minor temporal variation in the NO_X emissions.

To determine the 4-hour rolling averages, each period of 4 consecutive unit operating hours is assessed (*i.e.*, the current unit operating hour and the 3 unit operating hours immediately preceding it).

We are allowing the use of NO_X CEMS as an alternative to continuously monitoring fuel consumption and water or steam to fuel ratio because the majority of new turbines do not rely on water injection for NO_X control. Therefore, for those turbines, the monitoring originally required by subpart GG, 40 CFR part 60, is not appropriate. The use of a NO_X CEMS will show compliance with the NO_X standard of subpart GG over all operating ranges. Additionally, many of the units affected by subpart GG are already required to install and certify CEMS for NO_X under other requirements, such as the acid rain monitoring regulation in 40 CFR part 75, or through conditions in various permit requirements. To reduce the burden on these units, we are allowing the use of CEMS units that are certified according to the requirements of 40 CFR part 75. The 40 CFR part 75 testing procedures to certify the CEMS are nearly identical to those in 40 CFR part 60, and 40 CFR part 75 has rigorous quality assurance and quality control standards. Therefore, it is appropriate to allow the use of 40 CFR part 75 CEMS data for subpart GG compliance demonstration. A definition of unit operating hour, which includes the concepts of full and partial operating hours, is needed to clarify how to validate an hour when using CEMS and for the purpose of defining excess emissions and periods of monitor downtime.

B. Optional Fuel-Bound Nitrogen Allowance

The NO_X emission standard in 40 CFR 60.332 includes a NO_X emission allowance for fuel-bound nitrogen. The use of this allowance for fuel-bound nitrogen will be optional upon July 8, 2004. Owners or operators will be able to choose to accept a value of zero for the NO_X emission allowance. The NO_X emission limitations in many State permits are much more stringent than those of subpart GG of 40 CFR part 60. Many turbines are required by their permits to be fired only with pipeline quality natural gas, which is almost free of fuel-bound nitrogen. Therefore, these facilities are not likely to use the fuel-bound nitrogen credit.

C. Frequency of Fuel Nitrogen and Sulfur Content Sampling

Several revisions to the sampling frequency requirements for fuel nitrogen content and fuel sulfur content are being made.

Nitrogen Content for Turbines That Do Not Claim the Allowance for Fuel Bound Nitrogen

We are amending subpart GG of 40 CFR part 60 so that sources are required to monitor the nitrogen content of the fuel being fired in the turbine only if they claim the allowance for fuel-bound nitrogen. For sources that do not seek to use the fuel-bound nitrogen credit, sampling to determine the daily fuel nitrogen concentrations is not required.

Nitrogen and Sulfur Content for Turbines Firing Fuel Oil

The sampling frequency for determining the nitrogen and sulfur content of fuel oil has been amended. Previously for bulk storage fuels, sampling and analysis was required each time new fuel was added. The requirement to sample the nitrogen and sulfur content of the fuel each time fuel is transferred to the storage tank from any other source can be burdensome for a facility if there are one or more large bulk storage tanks which are filled by tanker trucks or isolated from the turbines during the filling process. If the fuel is not fed to the turbines during the filling process, no environmental benefit is gained by sampling every time oil is added from a tanker truck. Similarly, no environmental benefit is gained by sampling a tank which remains isolated from feeding turbines until it is filled. It is less burdensome to allow a tank to

be filled completely, regardless of how many tanker trucks it takes, and then drawing a sample of the combined fuel. In the end, this mixture of fuel is what will be fed to the turbines. Thus, we are eliminating the requirement to sample each time new fuel is added and are allowing the use of any of the four sampling options from 40 CFR part 75, appendix D. The four options are as follows: daily sampling, flow proportional sampling, sampling from a unit's storage tank, or sampling each delivery.

Sulfur Content for Turbines Firing Natural Gas

A definition for natural gas has been added to the definitions section. It is consistent with the latest definition in 40 CFR part 72. Owners and operators of turbines that are combusting natural gas are now provided with alternatives to demonstrate that the fuel meets the sulfur content requirement. Sulfur sampling is unnecessary for fuels that qualify as natural gas. As defined in the final rule, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet, which equates to about 0.068 weight percent sulfur, or 680 parts per million by weight (ppmw), or 338 parts per million by volume (ppmv) at 20 degrees Celsius. (The conversion factor from grains of total sulfur per 100 standard cubic foot (gr/scf) to ppmw and percent weight: multiply gr/scf by 3.4×10^3 to get ppmw; divide this product by 10^4 to get percent weight.) When natural gas is combusted, there is no possibility of exceeding the subpart GG, 40 CFR part 60, sulfur limit of 0.8 weight percent or 8000 ppmw.

Sulfur and Nitrogen Content for Turbines Firing Gaseous Fuels Other Than Natural Gas

Units that fire a gaseous fuel that is supplied without intermediate bulk storage, but is not natural gas, must determine and record the sulfur content and (if applicable) nitrogen content once per day. Alternatively, these units may follow one of two custom sulfur sampling schedules outlined in the final rule, or they may develop a custom schedule that is approved by the EPA Administrator. One custom schedule requires daily sampling for 30 consecutive unit operating days. Provided the data indicate compliance, the frequency can then be reduced according to specific criteria. Unit operating day is now defined in 40 CFR 60.331.

Units may also follow a custom schedule based on the 720-hour sulfur sampling demonstration described in 40 CFR part 75, appendix D. Under both schedules, if the margin of compliance is large, the sampling frequency can eventually be reduced to annual. We are codifying these two custom schedules that have routinely been approved under the subpart GG provision that allows sources to develop custom schedules for fuel sampling that must be approved by the EPA Administrator.

D. Steam Injection

Sources that are using water injection currently can monitor the ratio of water to fuel, as well as fuel consumption, to demonstrate compliance with the NO_X standard. We are allowing sources that are using steam injection to monitor the ratio of steam to fuel and fuel consumption to demonstrate compliance. Steam injection is another method of NO_X control, and water and steam injection are the wet methods usually used. Steam injection monitoring is an acceptable type of parametric emission monitoring method.

E. Test Methods for Sulfur Content and Nitrogen Content of Fuel

When subpart GG of 40 CFR part 60 was promulgated, no test methods were specified for monitoring the nitrogen content of the fuel. We are specifying American Society of Testing and Materials (ASTM) D2597–94 (1999), ASTM D6366–99, ASTM D4629–02, or ASTM D5762–02 as acceptable methods for liquid fuels. Under the National Technology Transfer and Advancement Act, we have identified these voluntary consensus standards and are citing them for use. We are not adding any methods for determining the fuel-bound nitrogen content of the fuel being fired for gaseous fuels because none were identified. We do not expect any source owner to use a gaseous fuel with sufficient fuel-bound nitrogen present to claim a credit. Any source owner proposing credit for fuel-bound nitrogen in a gaseous fuel will have to document an acceptable method. We have amended subpart GG to allow the use of most of the methods specified in sections 2.2.5 and 2.3.3.1.2 of 40 CFR part 75, appendix D to determine the total sulfur content of gaseous fuel. The alternative methods for total sulfur provide more flexibility and harmonize with the requirements in 40 CFR part 75. The method ASTM D3031–81 has been deleted from the final rule because it was discontinued by the ASTM in 1990 with no replacement. If the total sulfur content of the fuel being fired in the turbine is less than 0.4 weight percent, we are adding a provision that the following methods may be used to measure the sulfur content of the fuel: ASTM D4084–82 or 94, D5504–01, D6228–98, or the Gas Processors Association Method 2377–86. This provision is consistent with the provision in 40 CFR 60.13(j)(1) allowing alternatives to reference method tests to determine relative accuracy of CEMS for sources with emission rates demonstrated to be less than 50 percent of the applicable standard.

F. Performance Testing

To measure the NO_X and diluent concentration during the performance test, we are adding EPA Method 7E of 40 CFR part 60, appendix A, used in conjunction with EPA Method 3 or 3A of 40 CFR part 60, appendix A, as an acceptable alternative to EPA Method 20. In addition, we are adding ASTM D6522–00 as another alternative to EPA Method 20.

Subpart GG of 40 CFR part 60 previously required the NO_X initial compliance testing to be conducted at four different loads across the unit's operating range. This testing was required because of the difficulty in predicting which operating load will represent worst case conditions when monitoring operational data. Testing, therefore, was done across the operating range to determine the water to fuel ratio and fuel consumption needed to maintain NO_X compliance across the unit's normal operating range. One of the tests was required to be conducted at 100 percent of peak load. We are amending the final rule to allow one test point at 90 to 100 percent of peak load, or the highest load physically achievable in practice. Due to conditions that are beyond the control of the turbine operator, such as ambient conditions, it is often not possible for a turbine to be operated at 100 percent of the manufacturer's design capacity. Therefore, the requirement to test at 100 percent of peak load has been made more flexible.

Another change is that the initial performance test can be performed only at 90 to 100 percent of peak load or the highest physically achievable load in practice, instead of at four different loads, if the owner or operator chooses to use the NO_X CEMS monitoring option. The NO_X CEMS will provide realtime data on NO_X emissions for any given time of operation. This data provides credible evidence which can be used to determine the unit's compliance status on a continuous basis following the initial test. The availability of this continuous information through the use of NO_X CEMS after the initial performance testing justifies testing at a single load

for the initial compliance testing. We are also clarifying how data collected during a relative accuracy test audit (RATA) of the NO_X CEMS may be used to demonstrate compliance with the performance tests required by 40 CFR 60.8. The RATA consists of a minimum of nine 21-minute runs using EPA reference test methods, for a total of 189 minutes or just over 3 hours. This amount of sampling accompanied by sampling at multiple traverse points during a RATA provides enough representative emissions data to determine the unit's compliance status.

Finally, a statement has been added to clarify that if the turbine combusts both oil and gas, separate performance testing is required for each type of fuel combusted by the turbine, except for emergency fuel. This is appropriate due to the fact that NO_X emissions vary by fuel type.

G. Measurement After Duct Burner

For sources that are combined cycle turbine systems using supplemental heat, we have added an option that the turbine NO_X emissions may be measured after the duct burner rather than directly after the turbine. No additional NO_X allowance is given. A definition for duct burner has also been added to the definitions section of the final rule. For combined cycle units, there are several concerns with testing and monitoring NO_X at the turbine outlet. For example, it is questionable whether the turbine outlet location is suitable for installation of CEMS. Moreover, due to the high temperature and pressure of the turbine exhaust at that location, it may be difficult to conduct an EPA Method 20 performance test at the turbine outlet of a combined cycle unit. In addition, any combined cycle units that are subject to NO_X CEMS requirements for 40 CFR part 75 or subparts Da and Db of 40 CFR part 60 will most likely have installed the CEMS after the duct burner, on the heat recovery steam generator (HRSG) stack. Another reason to allow measurement of NO_X emissions after the duct burner is that add-on NO_X control systems such as selective catalytic reduction (SCR) are generally located after the duct burner; turbine NO_X performance testing should be conducted after the NO_X control device and would, therefore, include emissions from the duct burner.

H. Option To Not Use International Organization for Standardization (ISO) Correction

We have added an option to not use the ISO correction equation for the following units: Lean premix combustor turbines, units used in association with HRSG equipped with duct burners, and units with add-on emission controls. This option was added based on discussions with the Gas Turbine Association (GTA). The GTA indicated in letters to EPA on April 16, 2002 and May 30, 2002 that the ISO correction equation was not necessary for these units. These letters can be found in the docket. In addition, in response to public comments, we are not requiring the reporting of ambient conditions if you are not using the ISO correction factor.

I. Accuracy of Continuous Monitoring System (CMS) for Fuel Consumption and the Water or Steam to Fuel Ratio

The requirement that the CMS for the fuel consumption and water or steam to fuel ratio for the turbine be accurate to within 5 percent has been removed. The numerical value of water to fuel ratio that serves as a surrogate for the acceptable NO_X concentration is established at each facility. This is accomplished by simultaneously measuring the NO_X concentration and using a CMS to monitor the water or steam to fuel ratio that achieves that NO_X level at various turbine loads at the specific facility during a performance test. This calibration serves to assure that if the water or steam to fuel ratio is maintained above this surrogate value using the same CMS, then acceptable NO_X concentration levels are attained even if the actual numerical value is not correct. Hence, the requirement to be accurate within plus or minus 5 percent is not necessary.

J. Excess Emissions and Monitor Downtime

The excess emission reporting provisions under 40 CFR 60.334 have been amended to include definitions of excess emissions and monitor downtime periods for the various emissions and parameter monitoring requirements. Periods of monitor downtime were not previously defined, so we have added definitions for those periods. New provisions have been added for CEMS and parametric monitoring for certain units; therefore, it is necessary to define the excess emissions and monitor downtime for turbines using these new monitoring options.

K. Other Clarifications

Several other minor clarifications have been made to the final rule. They are as follows: (1) Indicated that the sulfur content standard in 40 CFR 60.333(b) of 0.8 percent by weight is equivalent to 8000 ppmw; (2) clarified the NO_X standard in 40 CFR 60.332(a)(1) to indicate that it is an emission concentration and should be ISO corrected (if required); and (3) clarified the NO_X emission concentration equation in 40 CFR 60.335(b)(1) to indicate it is a concentration instead of a rate and that it is on a dry basis.

III. Summary of Responses to Major Comments

The following sections provide a summary of the major public comments made during the public comment period for the proposed rule. A complete summary of the comments and responses can be found in the Summary of Public Comments and Responses document, which is available from several sources (*see* **ADDRESSES** section).

A. Fuel Sampling/Sulfur Content

Comment: Several commenters wanted to see changes in the fuel sampling strategies. Some commenters wanted to see less sampling requirements, while others wanted more stringent requirements. One commenter felt that eliminating the daily fuel total sulfur content sampling requirement is not environmentally beneficial, and creates a situation where the emission of sulfur compounds is presumptive with no measured foundation. Other commenters felt that EPA should provide additional options to sampling for nitrogen and sulfur content in fuel oil, particularly when the unit only combusts fuel oil on a limited basis.

Response: We did not make any changes to the fuel sampling requirements in the final rule. The amendments did not eliminate any requirements for natural gas sulfur content sampling. Rather, they provide optional (not mandatory) relief from monitoring the sulfur content of natural gas. Natural gas is defined in the final rule as having a sulfur content of 20 grains or less of total sulfur per 100 standard cubic feet, which equates to 0.068 weight percent sulfur, or 680 ppmw. When natural gas is combusted, there is no possibility of exceeding the subpart GG of 40 CFR part 60 sulfur limit of 0.8 weight percent.

The commenter is not correct in asserting that this new provision is "presumptive with no measured foundation." The final rule requires the owner or operator to document that the fuel meets the definition of natural gas in order to obtain the regulatory relief.

In regards to fuel oil, the revisions to § 60.334(i)(1) provide owners and operators with many options for scheduling of fuel oil sampling. They may sample on a per delivery basis; therefore, daily sampling is not a requirement. In addition, failure to sample deliveries of fuel oil if no fuel

oil has been combusted is not an excess emission if one of the other schedules has been retained. An owner or operator may utilize flow proportional sampling, which would require samples only if fuel oil is being combusted. Owners and operators are not precluded from taking one sample for the day for all units operated during an official "unit operating day." No changes have been made to the proposed regulatory text in response to this comment.

B. Monitoring

Comment: Several comments were received on the proposed continuous monitoring provisions. Commenters stated that EPA should withdraw the optional continuous emission monitoring provisions under § 60.334(c), (e), and (f) for turbines that do not use water or steam injection to comply with the applicable NO_X emission standards.

One commenter requested that EPA make clear that the choice of whether to use a NO_X CEMS is entirely at the discretion of the source owner or operator, even in those cases where a NO_X CEMS is installed. The commenter also requested that EPA make clear that nothing in the final rule is intended to impose new requirements, or to alter or prevent other determinations regarding the adequacy of monitoring to comply with subpart GG of 40 CFR part 60. Some commenters recommended that EPA make clear in the final rule or preamble that (1) alternatives approved by State and local agencies under State authority, or delegation of authority from EPA are also valid, and (2) these amendments do not impose any new requirements, or require revision of existing permits, but simply provide several pre-approved options for sources that do not want to seek case-by-case approval.

Another commenter recommended the addition of language to § 60.334(c) indicating that existing turbines under subpart GG of 40 CFR part 60 without water or steam injection that are not required to implement continuous direct or indirect NO_X monitoring under their current approvals may continue to operate under the provisions of their current approvals. The commenter stated that an annual NO_X stack test could serve as an appropriate alternative to a NO_X CEMS or parametric monitoring for an existing subpart GG turbine with low annual utilization (< 1500 hours per year). For a small baseload turbine, an existing quarterly stack testing requirement would be an appropriate CEMS or parametric monitoring alternative.

Four commenters stated that the proposed revisions would wrongly impose significant new requirements for ongoing NO_X compliance monitoring on mid-range stationary gas turbines and turbines in natural gas transmission. One commenter gathered over 100 permits, including construction and title V permits, for turbines subject to the NSPS. Examination of the gathered permits showed that continuous monitoring of emissions or parameters has typically not been required. The commenters expressed opposition to the provisions proposed in § 60.334(c), which they believed fail to address existing mid-range turbines subject to the NSPS because the vast majority of these turbines have neither CEMS nor an EPA-approved petition for alternative monitoring. Even natural gas transmission turbines with emission limits dramatically lower than the current NSPS limits are not typically required to install CEMS. Additionally, lean premix turbines have little possibility of exceeding the NSPS emission limit as it currently stands. The commenters requested that EPA revise § 60.334(c) to clearly state that monitoring requirements included in existing permits should not be revised as a result of this rulemaking. The commenters also did not support the provisions proposed in § 60.334(e) and (f) because the commenters believed the provisions would impose significant new regulatory requirements on new NSPS turbines in natural gas transmission service and other mid-range units. In addition, one commenter stated that in the memo in the docket, EPA ignored the costs for the significant new requirements which would be imposed, since most of the natural gas transmission and other mid-range units do not currently have CEMS installed. Therefore, in their opinion, EPA has failed to estimate the true impacts of the final rule, including the impacts related to increased monitoring, recordkeeping and reporting requirements for their industry. The commenters recommended that EPA write § 60.334(e) and (f) so that they do not impose CEMS or continuous parameter monitoring requirements on owner/operators that are not otherwise required to use CEMS or continuous parametric monitoring, and to consider the current Agency approved NO_X compliance monitoring techniques that are used by the natural gas transmission industry for NSPS turbines as alternatives to the continuous monitoring provisions included in part 75.

Two commenters stated the EPA should not rely on the May 31, 1994 memorandum from John Rasnic (EPA Applicability Determinations Index, Control No. 9700124) regarding compliance monitoring for turbines that use technology other than water injection as the basis for the proposed subpart GG revisions. One commenter requested that the 1994 memorandum be formally withdrawn by the agency.

Two commenters suggested that if EPA intends to impose new monitoring requirements for NSPS turbines, EPA should issue a new proposal with that intent expressly stated. One commenter further stated that the proposal should include the full range of compliance monitoring for natural gas combustion turbines, as currently approved by EPA in existing permits for NSPS turbines, and should be performed in conjunction with the revisions of the NSPS emission standards.

Response: We have clarified in the preamble that nothing in the final rule amendments is intended to impose new requirements for turbines constructed between 1977 and the effective date of the final rule amendments. Instead, we have described a number of acceptable continuous compliance methodologies (*e.g.*, the use of CEMS) for these units. We have added language to the preamble and rule which clarifies that continuous compliance methodologies already approved by EPA or by the local permitting authority are still valid. We do not agree that these revisions would impose new requirements for these turbines. We have ensured that the regulatory language is clear with respect to the use of CEMS as an option, and also made sure that any previously approved methods are still valid. Hence, for existing turbines covered under subpart GG of 40 CFR part 60, there are no compliance costs associated with these amendments.

Comment: One commenter requested that EPA provide the option of monitoring either O_2 or carbon dioxide (CO_2) as a diluent when using a NO_X CEMS in § 60.334(b), in the interest of consistency with 40 CFR part 75.

Response: We agree that it is acceptable to make the required dilution correction with data from a CO_2 monitor. In the final rule, § 60.334(b) has been revised to include the CO_2 correction procedure from Method 20. The CO_2 readings must be converted to equivalent O_2 using equations F–14a or F–14b in 40 CFR part 75, appendix F.

Comment: One commenter requested that EPA clarify whether the revised subpart GG, 40 CFR part 60, allows application of the 40 CFR part 75 O_2 (or CO_2) Diluent Cap provisions. This

provision allows substitution of an O_2 value of 19 percent for any hour where O_2 is measured at levels greater than 19 percent.

Response: We agree that it is acceptable to provide a diluent cap procedure for reducing CEMS data. This comment has been incorporated. Section 60.334(b)(3)(i) of the final rule allows the diluent cap value of 19.0 percent O_2 to be used to calculate the NO_X emissions whenever the quality-assured hourly O_2 concentration measured by the O_2 monitor (or calculated from a CO_2 monitor reading) is greater than 19.0 percent O_2. No alternative petition will be required.

Comment: One commenter stated that EPA should amend the monitoring provisions of § 60.334(a) to clarify that monitoring applies only to those turbines that must use water or steam injection to control NO_X emissions "to comply with the NO_X standards under § 60.332(a)." The commenter noted that some turbines may be able to comply with the subpart GG, 40 CFR part 60, NO_X standard uncontrolled, but need water or steam injection to comply with a more stringent NO_X standard.

Response: We do not agree with the commenter's suggested clarification that the monitoring requirements should apply only to turbines that use steam or water injection to control NO_X emissions to comply with the NO_X standards under § 60.332(a). Water injection is mentioned in § 60.334(a) because it was the only emission control technology available for turbines when subpart GG, 40 CFR part 60, was proposed back in 1977. As we have done in the past, the use of alternative continuous monitoring methods may be approved by EPA on a case-by-case basis for turbines that do not use water injection to control NO_X. Although a turbine may be able to meet the NO_X emission standard with other control technologies, continuous monitoring is needed to ensure that the emission limit is being met at all times.

Comment: One commenter expressed the view that the proposed rule failed to address the use of NO_X concentration data that have been "bias adjusted" under 40 CFR part 75. The commenter stated that EPA should acknowledge that sources cannot be required to use bias adjusted data, as was done in 40 CFR part 60, subpart Da. The commenter noted that some turbines with emissions significantly lower than their subpart GG, 40 CFR part 60, limit may prefer to simplify their reporting by utilizing the same bias adjusted data for subpart GG and 40 CFR part 75 and suggested the EPA make reporting of bias adjusted data for "excess emissions" monitoring optional.

Response: The commenter's suggestion was not incorporated. Combustion turbines covered under 40 CFR part 75 that use CEMS for NO_X compliance are required to monitor and report the NO_X emission rate in pounds per million british thermal units (lb/MMBTU) on an hourly basis. To achieve this, a NO_X-diluent CEMS is used to continuously measure the NO_X concentration (ppm) and either the percent O_2 or percent CO_2. These measured gas concentrations are used to calculate the required hourly NO_X emission rates. Under 40 CFR part 75, the relative accuracy test audit (RATA) of a NO_X-diluent CEMS is performed on a lb/MMBTU basis. If, during the RATA, the NO_X emission rates calculated from the CEMS data are biased low with respect to the emission rates derived from the EPA reference methods, a bias adjustment factor must be applied to the subsequent hourly NO_X emission rates. Since the bias adjustment factor is applied to the lb/MMBTU NO_X emission rates and not to the NO_X ppm values, and since diluent concentration data are never adjusted for bias under 40 CFR part 75, there is no need to mention bias-adjusted data in subpart GG of 40 CFR part 60. The subpart GG emission limits are in units of ppm of NO_X, corrected to 15 percent O_2. Therefore, any 40 CFR part 75 NO_X concentration or O_2 data used to assess compliance with these emission limits would not be bias-adjusted.

Comment: One commenter urged EPA to use its $PM_{2.5}$ precursor foundation (67 FR 39602, June 10, 2002) to impose an ammonia (NH_3) CEMS obligation on all gas turbines that utilize SCR as NO_X control, with quarterly reporting for NO_X and NH_3 emissions.

Response: Since ammonia is not regulated under subpart GG, 40 CFR part 60, we do not support adding a continuous monitoring requirement for ammonia to the NSPS.

Comment: Two commenters stated that some turbines in the gas transmission industry are diffusion flame combustors, yet are small (1200 HP, 11 MMBTU/hr). The commenter feels that since the manufacturer guarantee is 100 ppm while the NSPS emission limit is 150 ppm NO_X, that a mandatory CEMS requirement is inappropriate and imposes an unreasonable regulatory burden.

Response: As was stated in the preamble, we did not intend to impose any new requirements on existing turbines covered subpart GG, 40 CFR part 60, through the promulgation of the final rule. We have clarified in the final rule that (1) alternatives approved by State and local agencies under State authority, or delegation of authority from EPA are also valid, and (2) these amendments do not impose any new requirements, or require revision of existing permits, but simply provide several pre-approved options for sources that do not want to seek case-by-case approval.

Comment: One commenter wanted EPA to explicitly reference appendix F of 40 CFR part 60, regarding quality assurance procedures for NO_X CEMS.

Response: Continuous emission monitoring systems are used as an alternative to water to fuel ratio monitoring, to identify and report periods of excess emissions, and, therefore, appendix F, procedure 1, 40 CFR part 60, is not mandatory. Section 60.334(b)(4) has been removed.

Comment: Three commenters did not support the proposed changes presented in § 60.334(f), which address continuous parameter monitoring as an alternative to CEMS for new turbines that do not use steam or water injection to control NO_X emissions. The commenters noted that continuous parameter monitoring is not consistent with monitoring typically required for mid-range stationary gas turbines, including turbines used in natural gas transmission service, and would impose significant new regulatory requirements on these. Commenters recommended that EPA write the provisions in the final rulemaking to effect EPA's original intent of codifying the option to use continuous parameter monitoring, when otherwise required for other reasons such as 40 CFR part 75, without imposing significant new requirements on other owners or operators. The commenter also recommended that EPA explicitly state in the preamble that permitting authorities, under title V periodic monitoring or other programs, are not restricted to continuous monitoring of emissions or parameters and may continue to consider the full range of compliance monitoring options for gas-fired turbines. One commenter supported EPA's goal of allowing owners or operators the flexibility to use data from continuous parameter monitoring already required for other reasons to demonstrate compliance with the NSPS. However, the commenter does not support a mandatory requirement for continuous parameter monitoring and requests that EPA withdraw § 60.334(f) from the direct final and proposed rules.

In addition, two commenters stated that new lean premix turbines have little possibility of exceeding the NSPS emission limit as it currently stands.

Indeed, verification of lean premix combustion ensures NO_X emissions at levels far below the current NSPS emission limit. Equally, information about operation outside of lean premix does not provide meaningful information about whether a unit has failed to comply with the current NSPS emission limit.

Response: As was stated in the preamble, we did not intend to impose any new requirements through the promulgation of the final rule. We have clarified in the final rule and preamble that the amendments do not impose any new requirements but simply provide several pre-approved options for sources that do not want to seek case-by-case approval.

In regard to the comment that new lean premix turbines are able to comply with the current emission limit with little possibility of exceeding the standards, we plan to amend the emission limitations in subpart GG, 40 CFR part 60, as part of an upcoming rulemaking.

Comment: One commenter opposed and requested the removal of the parameter monitoring plan requirement proposed in § 60.334(g). They further stated that it does not streamline the differences between subpart GG, 40 CFR part 60, and 40 CFR part 75 appendix E requirements. According to the commenter, appendix E adequately addressed this issue. One commenter requested that the provisions in § 60.334(g), which address the use of performance test data to establish acceptable parameter ranges, be written to provide the opportunity for owners and operators to establish and/or adjust operating parameter limitations based on performance tests, engineering analysis, design specifications, manufacturer recommendations or other applicable information, such as a performance test on a similar unit. Since gas transmission units are load following, it may not be possible to operate at specific load conditions at the predetermined time scheduled for the performance test, and maximum and minimum load condition emissions may not be seen during the performance test. A similar unit, however, can exhibit representative emissions for developing parameter limitations.

Response: The requirement to develop and maintain a parameter monitoring plan has been retained in the final rule. For units that use continuous parameter monitoring to assess compliance with the emission limits under subpart GG, 40 CFR part 60, it is essential for the owner or operator to clearly identify the monitored parameters and their acceptable ranges, and to provide the technical basis for selecting those parameters and ranges. Section 60.334(g) of the final rule allows the owner or operator to supplement the parametric data recorded at the time of the initial performance test with other types of information, in order to establish the appropriate parametric ranges and values.

In response to the comment about units under appendix E, 40 CFR part 75, § 60.334(f) and (g) of the final rule make it clear that if the owner or operator performs the parametric monitoring described in section 2.3 of appendix E, 40 CFR part 75, and maintains the quality assurance (QA) plan described in section 1.3.6 of 40 CFR part 75, appendix B, this will satisfy the requirements of subpart GG of 40 CFR part 60. For the sake of completeness, for low mass emissions (LME) units, the final rule also allows the owner or operator to use the QA plan described in § 75.19(e)(5) to satisfy the parameter monitoring plan requirements of subpart GG.

Comment: Two commenters stated that continuous parameter monitoring is not appropriate for new diffusion flame turbines subject to NSPS. Some models of diffusion flame combustors are installed for the natural gas industry for which there are no predictive emission monitoring systems available. Development of one would impose an unreasonable burden on the industry.

Response: Predictive emission monitoring systems (PEMS), are very different from the parameter monitoring option that we have added to the final rule. Continuous parameter monitoring refers to the monitoring of operating conditions or parameters, such as turbine exhaust temperature, compressor discharge pressure, or any others which may be indicative of the unit's NO_X formation characteristics. Predictive emission monitoring systems, on the other hand, predict actual emission rates or concentrations from operating parameters that affect NO_X formation. Parameter monitoring oversees operating parameter boundaries, while PEMS measure emission rates or concentrations. Adding the option to continuously monitor parameters that are indicative of the unit's NO_X formation characteristics would not impose an unreasonable burden on the industry. No changes have been made from the proposed rule to the final rule to address this comment.

Comment: One commenter opposed the 4-hour averaging period to determine compliance. The commenter stated that EPA should base averaging times on the stated permit conditions of a Prevention of Significant Deterioration/New Source Review (PSD/NSR) permit issued by the permitting authority and that subpart GG, 40 CFR part 60, should remain silent on this issue other than the time it takes to conduct the required compliance stack testing.

Response: We do not agree with the commenter. The 4-hour averaging period has been retained in the final rule. The commenter is incorrect in asserting that subpart GG, 40 CFR part 60, should be silent on the issue of the averaging period for excess emission reporting. Each NSPS subpart that requires excess emission monitoring and reporting with respect to a particular emission limit must specify an averaging period. If a subpart GG turbine is subject to another more stringent NO_X emission limit with a different averaging period than subpart GG (*e.g.* a permit limit), and if the unit's operating permit requires excess emission reporting with respect to that limit, then two separate excess emission reports must be filed, *i.e.*, one to satisfy subpart GG requirements and the other to meet the permit requirement.

Comment: One commenter did not believe that EPA's attempt to distinguish between "excess emissions" and "deviations" is necessary since neither are violations under subpart GG, 40 CFR part 60. The commenter was also concerned that the choice of the term "deviation" could cause confusion in the context of title V permits and State Implementation Plans (SIP) and suggested the EPA either continue to use the term "excess emissions" for all reported parameters under subpart GG, or follow the terminology adopted in the Compliance Assurance Monitoring rule at 40 CFR part 64, which refers to parameter exceedances as "excursions."

Response: We agree with the commenter that it is not necessary to distinguish between "deviations" and "excess emissions." Both terms represent an averaging period during which a monitored parameter exceeds the limit specified in the final rule. Therefore, use of the term "deviation" in addition to "excess emissions" would be redundant. The final rule does not use the term "deviation."

Comment: One commenter requested clarification on § 60.334(j)(2), which says that periods of excess emissions and monitor downtime end on the date and hour of the next valid sample. The commenter stated that EPA should clarify that the period of excess emissions and/or monitor downtime from the start date to the next valid sample includes only unit operating hours.

Another commenter requested that the 4-hour rolling averaging period for NO_X emissions extend backward three operating hours, not three quality assured operating hours. The commenter noted that the standard CEMS vendor software is configured to look back a fixed number of calendar or on-line hours, but not quality assured hours.

Response: We agree with both commenters, and have written the final rule accordingly. "Quality assured" has been removed when used in reference to the rolling averaging period.

Comment: Two commenters requested clarification on the issue of compliance during startup and shutdown. One commenter asked whether startup and shutdown hours can be excluded from the 4-hour NO_X CEMS rolling averages used for compliance determination. The commenter also asked how site specific startup and shutdown periods should be established and whether the site can simply use manufacturer's recommended durations. One commenter stated that EPA should modify § 60.334(j)(1)(iii)(A) to add language clarifying that the average excludes emissions from startup, shutdown, and malfunctions.

Two commenters remarked that the requirement in § 60.334(j)(1)(i)(A) that "any unit operating hour in which no water or steam is injected into the turbine shall also be considered a deviation" does not appear to exempt startup or shutdown transients. One commenter said that any gas turbine equipped with steam or water injection for NO_X control would always have a deviation during startup and shutdown transients. According to the commenter, steam or water injection is usually initiated between 20 to 50 percent of base load during startup and is likewise discontinued during the shutdown transient. One commenter recommended revising the wording of the last sentence of the section to read as follows: "Any unit operating hour in which no water or steam is injected into the turbine shall also be considered a deviation *for purposes of reporting periods of startup, shutdown, and malfunction.*"

Response: In response to these comments, § 60.334(j) of the final rule has been written to clearly state that excess emissions must be recorded during all periods of unit operation, including startup, shutdown and malfunction. All excess emissions are reported and categorized. Note that the final rule does not use the term "deviation." Startup and shutdown are two of those categories. We recognize that even for well-operated units with efficient NO_X emission controls, excess emission "spikes" during unit startup and shutdown are inevitable, and malfunctions of emission controls and process equipment occasionally occur. However, at all times, including periods of startup, shutdown and malfunction, § 60.11(d) requires affected units to be operated in a manner consistent with good air pollution control practice for minimizing emissions. Excess emission data may be used to determine whether a facility's operation and maintenance procedures are consistent with § 60.11(d).

C. Test Methods and Procedures

Comment: One commenter requested that EPA allow performance tests to be conducted in the normal operating range of the gas turbine and allow for testing units that cannot be operated at "peak load" due to process constraints. The commenter suggested that instead of 90 to 100 percent of peak load, the owner or operator could test at the highest achievable load point if 90 to 100 percent of peak load could not physically be achieved in practice.

Response: The final rule incorporates the commenter's suggested revisions to § 60.335(b)(2). It is reasonable to make allowance for units that are not physically capable of attaining 90-to-100 percent of peak load.

Comment: One commenter suggested that if the permitted operating range of a turbine is sufficiently narrow, the required number of load levels for performance testing should be appropriately reduced. The commenter suggested that a minimum load level spacing of 20 percent be established.

Response: The requirement for four points for performance testing is necessary. The purpose of the data is to establish a water to fuel ratio. Two points are not enough to establish a statistically relevant relationship. Thus, we have not made any changes from the proposed rule to the final rule related to this comment.

Comment: Two commenters noted that the reference in § 60.335(a) to the procedures in section 6.5.6.3(a) and (c) of 40 CFR part 75, appendix A, should be changed to section 6.5.6.3 (a) and (b). Similarly, one commenter requested that the single measurement point identified in sections 6.5.6(b)(4) and 6.5.6.3(b) of 40 CFR part 75, appendix A, be added to the final rule. The commenter noted that the stratification testing procedure for a single measurement point is identical to the long and short measurement lines and the acceptance criteria for a single measurement point is more stringent.

Response: We agree with the commenter that measurement at a single point is appropriate in certain situations. In the interest of consistency with 40 CFR part 75, we have indicated in the final rule that data collected following section 6.5.6.1 can be used. Also, we have written the initial performance test requirements in § 60.335(a) to reflect that this option is available. However, because recently proposed revisions to Method 7E have more restrictive criteria at lower concentrations than those in section 6.5.6.3 of 40 CFR part 75, it is not appropriate to allow consistency in this case. Therefore, we have removed reference to section 6.5.6.3 of 40 CFR part 75 in the final rule. It is still possible to use the same data and choose the more restrictive number of sampling locations.

Comment: Two commenters recommended that a subparagraph be added to § 60.335(a) to clearly distinguish requirements for owners and operators that opt for using ASTM D6522–00 or EPA Method 7E instead of Method 20. One commenter suggested that the following should be appended to paragraph (a): "Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section."

The commenters noted that much of the new language EPA has added to the test methods and procedures under § 60.335(a) pertains to RATA and as these requirements are being applied to performance testing, any reference to a RATA is inappropriate and should be replaced with "performance testing."

Response: We agree with the commenter that requirements for those opting to use ASTM D6522–00 and/or EPA Method 7E should be clarified. Section 60.335(a) has been modified accordingly. We also agree that references to a RATA in § 60.335(a) should be deleted and replaced with "performance testing" and have written the final rule accordingly.

Comment: Two commenters requested that EPA revise § 60.335(a), which specifies that owners or operators choosing to use EPA Methods 7E and 3A (or 3) for NO_X performance testing must perform a stratification test for NO_X and diluent under 40 CFR part 75, appendix A, section 6.5.6.1(a)–(e) in order to determine if subsequent RATA testing will occur along a short or long reference method measurement line. One commenter appreciated EPA's proposal to add the option of using a short measurement line, but did not understand why a source that chooses to use the long reference measurement line would need to perform the stratification

test. One commenter stated that if a source agrees to use the most stringent options (*i.e.*, the long measurement line), it would seem unnecessary to require a stratification check.

Response: Section 60.335(a) applies to a performance test, not a RATA. We agree that if a source provides initial documentation that stratification does not exist, it is appropriate to have a reduced number of sampling points. We also agree that a source can skip the stratification test and default to using a multi-hole probe, and § 60.335 has been modified accordingly. However, because it is possible to have spatial stratification due to several reasons such as ammonia injection that would not be accounted for with the long measurement line, we are requiring documentation that stratification does not exist. We have also indicated that the use of data following section 6.5.6.1 of 40 CFR part 75 can be used. In addition, we have reserved a paragraph in § 60.335(a)(5)(i)(A) that will give the option of using stratification testing protocols that were proposed for Methods 7E and 3A in a separate **Federal Register** action.

D. ISO Correction

Comment: Two commenters recommended the removal of the ISO correction calculation. According to one commenter, the calculation is not practical for the modern turbine, and incorporation of the ISO correction factor within a CEMS requires burdensome administrative changes and unnecessary certification. As an alternative to removal of the ISO correction calculation, the commenter expressed support for making the ISO correction optional for specific gas turbines.

Another commenter recommended that EPA harmonize subpart GG, 40 CFR part 60, with 40 CFR part 75 monitoring requirements, eliminating any requirement to correct to ISO conditions, instead correcting to 15 percent O_2. The commenter also said that EPA should recognize the use of water injection as an add-on emission control device. The commenter noted that many lean premix units operate in limited use diffusion flame mode with water injection for emissions control and recommended that EPA recognize these dual-fuel units as lean premix where the primary fuel is natural gas combusted in lean premix mode. Further, they suggested that EPA exempt from ISO correction units that employ water injection when monitored in accordance with 40 CFR part 75 requirements. Similarly, one commenter recommended that diffusion flame units using water injection to control NO_X be exempt from the ISO data correction. Their rationale is that water injection cools the flame temperature to a level where NO_X is no longer primarily produced by thermal processes (much like lean premix, where the majority of NO_X is not produced thermally).

One commenter suggested that any turbine equipped with a NO_X CEMS be provided the option of not applying the ISO correction, irrespective of its design or configuration.

One commenter observed that the use of the ISO correction equation has no technical basis for gas turbines with lean premix combustors or for diffusion flame combustors with water or steam injection and NO_X levels significantly below the subpart GG, 40 CFR part 60, levels of 75 ppm.

Response: No adequate rationale was provided for exempting all turbines from the ISO correction factor. The ISO correction factor was initially developed for diffusion flame units, and no rationale has been provided for making it optional for these units. The ISO correction factor continues to be appropriate for diffusion flame units and water or steam injected units. The need for the ISO correction factor will continue as we begin the process of revising the emission limits in subpart GG, 40 CFR part 60, in the near future. We have also clarified in the final rule that when a unit is capable of using both lean premix and diffusion flame modes, it is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

Comment: Two commenters recommended that EPA remove the requirement to record ambient conditions when operating a turbine. One commenter stated that this requirement is burdensome and unnecessary and adds an administrative requirement that has no bearing on the environment. One commenter stated that for turbine units that are exempt from applying the ISO correction or which apply worst case ambient conditions to make the ISO corrections, the reporting of ambient conditions is unnecessary and represents a significant burden, since they are not collecting this data on-site.

Response: The ambient condition data is not used for any purpose other than the ISO correction. Therefore, we agree that the requirement in the proposed § 60.334(j)(1)(i)(C) and (iii)(C) to report the ambient conditions is unnecessary for those turbines for which the ISO correction is optional under § 60.335(b)(1). Also, reporting of ambient conditions is not necessary if an owner or operator chooses to calculate and apply a worst case ISO correction factor as specified in § 60.334(b)(3)(ii). Reporting of ambient conditions is still necessary for turbines that are required to use the ISO correction factor and do not opt to use a worst case ISO correction factor. We have written the final rule accordingly.

E. Emission Standards

Comment: A few commenters suggested revising the emission limits for sulfur and nitrogen in subpart GG, 40 CFR part 60.

Response: We will address emission limits in a future rulemaking amending subpart GG. We have not amended the emission limitations at this time.

F. Duct Burners

Comment: One commenter expressed the opinion that the option to measure gas turbine NO_X emissions in the exhaust stream after the duct burner rather than directly after the turbine is not viable as written because it does not account for the additional NO_X contribution from the duct burner. The commenter stated that the final rule should be written to provide for the duct burner NO_X contribution.

Response: The purpose of the final rule amendment was to allow owners and operators the flexibility of making one measurement downstream of the duct burner since many turbines are able to comply with the NO_X limit even with the potential NO_X contribution resulting from the duct burner. Accounting for the NO_X contribution from the duct burner would require two NO_X measurements, which clearly defeats the purpose of the amendment. Furthermore, owners and operators still have the option of simply measuring NO_X emissions in the turbine exhaust, prior to the duct burner. For these reasons, we disagree with the commenter and have not made any changes from the proposed rule to the final rule with respect to this provision.

IV. Environmental and Economic Impacts

The final rule amendments will not have any significant economic or environmental impacts. The amendments have been written primarily to codify routine testing and monitoring alternatives that have previously been approved by us. We are not introducing any new emission limitations, control requirements, or monitoring requirements. We are attempting to reduce the testing, monitoring, and reporting burden by

harmonizing with the requirements of 40 CFR part 75, since many gas turbines are subject to it as well as subpart GG of 40 CFR part 60.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

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

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

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

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

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

It has been determined that the final rule is not a "significant regulatory action" under the terms of Executive Order 12866 and is therefore not subject to EO 12866 review.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. 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 are listed in 40 CFR part 9 and 48 CFR chapter 15.

The amendments contain no changes to the information collection requirements of the current NSPS that would increase the burden to sources, and the currently approved OMB information collection requests are still in force for the amended rule. Some amendments in the final rule, such as allowing the use of CEMS to measure NO_X emissions, are provided as an option to sources, and should reduce burden to those sources who already have a CEMS in place for other regulatory reasons, such as the Acid Rain requirements in 40 CFR part 75. Other amendments, such as the allowance of parametric monitoring in place of water to fuel ratio monitoring, do not result in additional recordkeeping and reporting requirements beyond those already required.

C. Regulatory Flexibility Analysis

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with the final rule.

For purposes of assessing the impacts of the final rule on small entities, small entity is defined as: (1) A small business whose parent company has fewer than 100 or 1,000 employees, or fewer than 4 billion kW-hr per year of electricity usage, depending on the size definition for the affected North American Industry Classification System (NAICS) code; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. It should be noted that small entities in six NAICS codes may be affected by the final rule, and the small business definition applied to each industry by NAICS code is that listed in the Small Business Administration (SBA) size standards (13 CFR part 121).

After considering the economic impacts of the final rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant adverse economic impact on small entities, since the primary purpose of the regulatory flexibility analysis is to identify and address regulatory alternatives "which minimize any significant economic impact of the proposed rule on small entities." 5 U.S.C. §§ 603 and 604. Thus, an agency may conclude that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule. Our conclusion that today's final rule will relieve regulatory burden on small entities is based primarily upon the estimated cost savings to turbine owners and operators as a result of the revisions to 40 CFR part 60, subpart GG, that are presented earlier in this preamble. These cost savings will be experienced by turbines owned and operated by small entities as well as large ones. Using the existing combustion turbines inventory as a measure of which industries may install new turbines in the future, presuming the existing mix of current combustion turbines is a good approximation of the mix of turbines that will be installed and affected by the final rule up to 2007, 2.5 percent of new turbines overall will likely be owned and operated by small entities. Of these entities, a majority of these are owned and operated by small communities.

For more information on the results of the analysis of small entity impacts, please refer to the economic impact analysis in the docket.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost effective, or least burdensome alternative that achieves the objective of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative

other than the least costly, most cost effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

The EPA has determined that the final rule amendments contain no Federal mandates that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. Thus, the amendments are not subject to the requirements of sections 202 and 205 of the UMRA. In addition, EPA has determined that the amendments contain no regulatory requirements that might significantly or uniquely affect small governments because they contain no requirements that apply to such governments or impose obligations upon them. Therefore, the final rule amendments are not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999) requires us 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" are defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

The final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Today's action codifies alternative testing and monitoring procedures that have routinely been approved by EPA. There are minimal, if any, impacts associated with this action. Thus, Executive Order 13132 does not apply to the final rule amendments.

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

Executive Order 13175 (65 FR 67249, November 6, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." "Policies that have tribal implications" is defined in the Executive Order to include regulations that have "substantial direct effects on one or more Indian tribes, on the relationship between the Federal government and the Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes."

The final rule does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. We do not know of any stationary gas turbines owned or operated by Indian tribal governments. However, if there are any, the effect of the final rule on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to the final rule.

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

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

We interpret Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. The final rule is not subject to Executive Order 13045 because it is based on technology performance and not on health or safety risks.

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

The final rule is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

These final rule amendments involve technical standards. The EPA cites the following methods in the final rule amendments: EPA Methods 1, 3, 3A, 7E, and 20 of 40 CFR part 60, appendix A; and PS 2 and 3 of 40 CFR part 60, appendix B. In addition, these final rule amendments cite the following standards that are also incorporated by reference (IBR) in 40 CFR part 60, section 17: ASTM D129–00, ASTM D1072–80 or –90 (Reapproved 1999), ASTM D1266–98, ASTM D1552–01, ASTM D2597–94 (Reapproved 1999), ASTM D2622–98, ASTM D3246–81 or –92 or –96, ASTM D4084–82 or –94, ASTM D4294–02, ASTM D4468–85 (Reapproved 2000), ASTM D4629–02, ASTM D5453–00, ASTM D5504–01, ASTM D5762–02, ASTM D6228–98, ASTM D6366–99, ASTM D6522–00, ASTM D6667–01, and Gas Processors Association Standard 2377–86.

Consistent with the NTTAA, EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods/performance specifications. No applicable voluntary consensus standards were identified for PS 3. The search and review results have been documented and are placed in the docket (OAR–2002–0053) for the final rule amendments.

One voluntary consensus standard was identified as an acceptable alternative to the EPA methods specified in the final rule amendments. The standard ASTM D6522–00, "Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers," is cited in the final rule amendments as an acceptable alternative to EPA Methods 3A, 7E, and 20 for identifying nitrogen oxide and oxygen concentration when the fuel is natural gas. This standard, ASTM D6522–00, has been also IBR in 40 CFR part 60, section 17.

In addition to the voluntary consensus standards EPA uses in the final rule amendments, the search for emissions measurement procedures identified eight other voluntary consensus standards. The EPA determined that seven of these eight standards identified for measuring air emissions or surrogates subject to emission standards in the final rule amendments were impractical alternatives to EPA test methods/performance specifications for the purposes of these final rule amendments. Therefore, the EPA does not intend to adopt these standards. See the docket for the reasons for the determinations of these seven methods.

Sections 60.334 and 60.335 of the final rule amendments to subpart GG, 40 CFR part 60, discuss the EPA testing methods, performance specification, and procedures required. Under §§ 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. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing the final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. The final rule is not a "major rule" as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

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

Dated: June 24, 2004.

Michael O. Leavitt,

Administrator.

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

PART 60—[Amended]

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

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

Subpart A—[AMENDED]

■ 2. Section 60.17 is amended by:
■ a. Removing and reserving paragraph (a)(38);
■ b. Revising paragraph (a) introductory text;
■ c. Revising paragraph (a)(8);
■ d. Revising paragraph (a)(15);
■ e. Revising paragraph (a)(18);
■ f. Revising paragraph (a)(20);
■ g. Revising paragraph (a)(33);
■ h. Revising paragraph (a)(43);
■ i. Revising paragraph (a)(50);
■ j. Adding paragraphs (a)(65) through (a)(75); and
■ k. Adding paragraph (m).

The revisions and additions read as follows:

§ 60.17 Incorporation by Reference

* * * * *

(a) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959; or ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106.

* * * * *

(8) ASTM D129–64, 78, 95, 00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for appendix A: Method 19, 12.5.2.2.3; §§ 60.106(j)(2) and 60.335(b)(10)(i).

* * * * *

(15) ASTM D1072–80, 90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.335(b)(10)(ii).

* * * * *

(18) ASTM D1266–87, 91, 98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j)(2) and 60.335(b)(10)(i).

* * * * *

(20) ASTM D1552–83, 95, 01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for appendix A: Method 19, Section 12.5.2.2.3; §§ 60.106(j)(2) and 60.335(b)(10)(i).

* * * * *

(33) ASTM D2622–87, 94, 98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry," IBR approved for §§ 60.106(j)(2) and 60.335(b)(10)(i).

* * * * *

(43) ASTM D3246–81, 92, 96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b)(10)(ii).

* * * * *

(50) ASTM D4084–82, 94, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for § 60.334(h)(1).

* * * * *

(65) ASTM D2597–94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for § 60.335(b)(9)(i).

(66) ASTM D4294–02, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X–Ray Fluorescence Spectrometry, IBR approved for § 60.335(b)(10)(i).

(67) ASTM D4468–85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for § 60.335(b)(10)(ii).

(68) ASTM D4629–02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection, IBR approved for § 60.335(b)(9)(i).

(69) ASTM D5453–00, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.335(b)(10)(i).

(70) ASTM D5504–01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and

Chemiluminescence, IBR approved for § 60.334(h)(1).

(71) ASTM D5762–02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for § 60.335(b)(9)(i).

(72) ASTM D6228–98, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for § 60.334(h)(1).

(73) ASTM D6366–99, Standard Test Method for Total Trace Nitrogen and Its Derivatives in Liquid Aromatic Hydrocarbons by Oxidative Combustion and Electrochemical Detection, IBR approved for § 60.335(b)(9)(i).

(74) ASTM D6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for § 60.335(a).

(75) ASTM D6667–01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.335(b)(10)(ii).

* * * * *

(m) This material is available for purchase from at least one of the following addresses: The Gas Processors Association, 6526 East 60th Street, Tulsa, OK, 74145; or Information Handling Services, 15 Inverness Way East, PO Box 1154, Englewood, CO 80150–1154. You may inspect a copy at EPA's Air and Radiation Docket and Information Center, Room B108, 1301 Constitution Ave., NW., Washington, DC 20460.

(1) Gas Processors Association Method 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, IBR approved for § 60.334(h)(1).

Subpart GG—[Amended]

■ 3. Section 60.331 is amended by adding paragraphs (s) through (y) to read as follows:

§ 60.331 Definitions.

* * * * *

(s) *Unit operating hour* means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

(t) *Excess emissions* means a specified averaging period over which either:

(1) The NO_X emissions are higher than the applicable emission limit in § 60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in § 60.333; or

(3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) *Natural gas* means a naturally occurring fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

(v) *Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, *etc.*, to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

(w) *Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) *Diffusion flame stationary combustion turbine* means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) *Unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

■ 4. Section 60.332 is amended by:

■ a. Revising the terms to the equations in paragraphs (a)(1) through (2);

■ b. Redesignating paragraph (a)(3) as (a)(4);

■ c. Revising newly designated paragraph (a)(4); and

■ c. Adding a new paragraph (a)(3).

The revisions and additions read as follows:

§ 60.332 Standard for nitrogen oxides.

(a) * * *

(1) * * *

Where:

STD = allowable ISO corrected (if required as given in § 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) * * *

Where:

STD = allowable ISO corrected (if required as given in § 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this seciton is optional. That

is, the owner or operator may choose to apply a NO_X allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO_X emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under § 60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NO_X percent by volume)
N ≤ 0.015	0
0.015 < N≤ 0.1	0.04(N)
0.1 < N ≤ 0.25 ..	0.004+0.0067(N–0.1)
N > 0.25	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by § 60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the **Federal Register**.

* * * * *

■ 5. Section 60.333 is amended by revising paragraph (b) to read as follows:

§ 60.333 Standard for sulfur dioxide.

* * * * *

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

■ 6. Section 60.334 is amended by:
■ a. Revising paragraphs (a) and (b);
■ b. Redesignating paragraph (c) as paragraph (j);
■ c. Adding a new paragraph (c);
■ d. Adding paragraphs (d) through (i);
■ e. Revising newly designated paragraph (j) introductory text, (j)(1) and (j)(2); and
■ f. Adding paragraph (j)(5).

The revisions and additions read as follows:

§ 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_X emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F–14a or F–14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO_X) and a percent O_2 basis for oxygen; or

(ii) On a ppm at 15 percent O_2 basis; or

(iii) On a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O_2).

(2) As specified in § 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in § 60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NO_X and diluent, the data acquisition and handling system must calculate and record the hourly NO_X emissions in the units of the applicable NO_X emission standard under § 60.332(a), *i.e.*, percent NO_X by volume, dry basis, corrected to 15 percent O_2 and International Organization for Standardization (ISO) standard conditions (if required as given in § 60.335(b)(1)). For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(iii) If the owner or operator has installed a NO_X CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in § 60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_X emissions, the owner or operator may, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA or local permitting authority approval of a petition for an alternative procedure of continuously monitoring compliance with the applicable NO_X emission limit under § 60.332, that approved procedure may continue to be used, even if it deviates from paragraph (a) of this section.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO_X emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO_X CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_X emissions may elect to use a NO_X CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. An acceptable alternative to installing a CEMS is described in paragraph (f) of this section.

(f) The owner or operator of a new turbine who elects not to install a CEMS under paragraph (e) of this section, may instead perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO_X formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in the lean premixed (low-NO_X) combustion mode.

(3) For any turbine that uses SCR to reduce NO_X emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in § 75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under § 60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in § 75.19 of this chapter or the NO_X emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in § 75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference-see § 60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (*i.e.*, if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in § 60.332). The nitrogen content of the fuel shall be determined using methods described in § 60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in § 60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be

substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in § 60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(*1*) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*2*) of this section.

(*2*) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*3*) of this section.

(*3*) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (*i.e.*, the maximum total sulfur content of natural gas as defined in § 60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.332, as established during the performance test required in § 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in § 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of § 60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in § 60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NO_X and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in § 60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NO_X concentration" is the arithmetic average of the average NO_X concentration measured by the CEMS for a given hour (corrected to 15 percent O_2 and, if required under § 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_X concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_X concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in § 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of § 60.335(b)(1).

(iv) For turbines required under paragraph (f) of this section to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (*i.e.*, daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

* * * * *

(5) All reports required under § 60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter.

■ 7. Section 60.335 is revised to read as follows:

§ 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in § 60.8, using either

(1) EPA Method 20,

(2) ASTM D6522–00 (incorporated by reference, see § 60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO_X and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO_X concentration during the stratification test; or

(B) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in § 60.332 and shall meet the performance test requirements of § 60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{Xo}) corrected to 15 percent O_2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$NO_X = (NO_{Xo})(P_r/P_o)^{0.5}\, e^{19\,(H_o - 0.00633)}\, (288°K/T_a)^{1.53}$$

Where:

NO_X = emission concentration of NO_X at 15 percent O_2 and ISO standard ambient conditions, ppm by volume, dry basis,

NO_{Xo} = mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O_2,

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

P_o = observed combustor inlet absolute pressure at test, mm Hg,

H_o = observed humidity of ambient air, g H_2O/g air,

e = transcendental constant, 2.718, and

T_a = ambient temperature, °K.

(2) The 3-run performance test required by § 60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these

requirements, performance testing is not required for any emergency fuel (as defined in § 60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_X emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_X emission limit in § 60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with § 60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00 (incorporated by reference, see § 60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.332 NO_X emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in § 60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in § 60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_X CEMS under § 60.334(e), then the initial performance test required under § 60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under § 60.332 and to provide the required reference method data for the RATA of the CEMS described under § 60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator is required under § 60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in § 60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597–94 (Reapproved 1999), D6366–99, D4629–02, D5762–02 (all of which are incorporated by reference, *see* § 60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under § 60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01 (all of which are incorporated by reference, *see* § 60.17); or

(ii) For gaseous fuels, ASTM D1072–80, 90 (Reapproved 1994); D3246–81, 92, 96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see § 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in § 60.8 to ISO standard day conditions.

[FR Doc. 04–14825 Filed 7–7–04; 8:45 am]
BILLING CODE 6560–50–P

Subpart F—California

■ 2. Section 52.220 is amended by adding paragraphs (c)(120)(i)(C), (331)(i)(B), and (332)(i)(A)(*2*) to read as follows:

§ 52.220 Identification of plan.

* * * * *

(c) * * *

(120) * * *

(i) * * *

(C) Previously approved on July 7, 1982 in paragraph (c)(120)(i)(A) of this section and now deleted without replacement Rule 425.

* * * * *

(331) * * *

(i) * * *

(B) South Coast Air Quality Management District.

(*1*) Rule 461, originally adopted on January 9, 1976 and amended on January 9, 2004.

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(332) * * *

(i) * * *

(A) * * *

(*2*) Rule 415, originally adopted on November 4, 1977 and revised on May 18, 2004.

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[FR Doc. 05–3358 Filed 2–18–05; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[OAR–2002–0049; FRL–7874–9]

RIN 2060–AJ68

Standards of Performance for Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974, and on or Before August 17, 1983; and Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 17, 1983

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; amendments.

SUMMARY: This action promulgates amendments to the new source performance standards for electric arc furnaces constructed after October 21, 1974, and on or before August 17, 1983, and the new source performance standards for electric arc furnaces constructed after August 17, 1983. The final amendments add alternative requirements for monitoring emissions from furnace exhausts and make minor editorial corrections.

EFFECTIVE DATE: February 22, 2005.

ADDRESSES: The EPA has established an official public docket for this action including both Docket No. OAR–2002–0049 and Docket No. A–79–33. All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket* (or Docket No. A–79–33). Not all docket materials are available electronically. The materials in Docket No. A–79–33 are in hard copy form and are publicly available through the docket facility as set forth below. Although listed in the index, some information is not publicly available, *i.e.*, confidential business information or other information whose disclosure is restricted by statute. Certain other information, such as copyrighted materials, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy form at the New Source Performance Standards for Electric Arc Furnaces Docket, Docket ID No. OAR–2002–0049 (or A–79–33), EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Kevin Cavender, Emission Standards Division, Office of Air Quality Planning and Standards (C439–02), Environmental Protection Agency, Research Triangle Park, NC 27711, telephone number (919) 541–2364, electronic mail (e-mail) address, *cavender.kevin@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does This Action Apply to Me?

Categories and entities potentially regulated by this action include:

Category	NAICS code [1]	Examples of regulated entities
Industry	331111	Steel manufacturing facilities that operate electric arc furnaces.
Federal government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industry Classification System.

This description is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your facility is regulated by this action, you should examine the applicability criteria in 40 CFR 60.270 (for electric arc furnaces constructed after October 21, 1974, and on or before August 17, 1983) or 40 CFR 60.270a (for electric arc furnaces and argon-oxygen decarburization vessels constructed after August 7, 1983), as applicable. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. Where Can I Get a Copy of This Document and Other Related Information?

In addition to being available in the docket, an electronic copy of today's final rule amendments will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following the Administrator's signature, a copy of the final rule amendments will be placed on the TTN's policy and guidance page for 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.

C. What Are the Judicial Review Requirements?

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of the final rule amendments is available only by filing a petition for review in the U.S.

Court of Appeals for the District of Columbia Circuit by April 25, 2005. Under section 307(d)(7)(B) of the CAA, only an objection to the final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Under section 307(b)(2) of the CAA, the requirements that are the subject of today's final rule amendments may not be challenged separately in civil or criminal proceedings brought by the EPA to enforce these requirements.

D. How Is This Document Organized?

The information in this preamble is organized as follows:

II. Background

A. What Is an Electric Arc Furnace?

An electric arc furnace (EAF) is a metallurgical furnace used to produce carbon and alloy steels. The input material to an EAF is typically 100 percent scrap steel. Cylindrical, refractory lined EAF are equipped with carbon electrodes to be raised or lowered through the furnace roof. With electrodes retracted, the furnace roof can be rotated to permit the charge of scrap steel by overhead crane. Alloying agents and fluxing materials usually are added through doors on the side of the furnace. Electric current is passed between the electrodes and through the scrap, generating arcing and the generation of enough heat to melt the scrap steel charge. After the melting and refining periods, impurities (in the form of a slag) and the refined steel are poured from the furnace.

The production of steel in an EAF is a batch process. Cycles, or heats, range from about 1½ to 5 hours to produce carbon steel and from 5 to 10 hours to produce alloy steel. Scrap steel is charged to begin a cycle, and alloying agents and slag forming materials are added for refining. Stages of each cycle normally are charging, melting, refining (which usually includes oxygen blowing), and tapping.

All of those operations generate particulate matter (PM) emissions. Emission control techniques involve an emission capture system and a gas cleaning system. Emission capture systems used in the industry include direct shell (fourth hole) evacuation, side draft hoods, combination hoods, canopy hoods, scavenger ducts, and furnace enclosures. Direct shell evacuation (DEC) consists of ductwork attached to a separate, or fourth hole, in the furnace roof which draws emissions to a gas cleaner. The DEC system works only when the furnace is up-right and the roof is in place. The side draft hoods collect furnace off gases from around the electrode holes and the work doors after the gases leave the furnace. The combination hood incorporates elements from the side draft and direct shell evacuation systems. Canopy hoods and scavenger ducts are used to address charging and tapping emissions. Baghouses are typically used as the gas cleaning system.

B. What Are the Current Requirements of the New Source Performance Standards for Electric Arc Furnaces?

The new source performance standards (NSPS) for EAF constructed after October 21, 1974, and on or before August 17, 1983 (40 CFR part 60, subpart AA) were first promulgated on September 23, 1975 (40 FR 43850). The NSPS for EAF constructed after August 17, 1983 (40 CFR part 60, subpart AAa) were first promulgated on October 31, 1984 (49 FR 43845). Both subparts limit the allowable PM concentration in the exhaust of an EAF emission control device to 12 milligrams per dry standard cubic meter (mg/dscm) or 0.0052 grains per dry standard cubic foot (gr/dscf). In addition to the PM emission limit, both subparts limit visible emissions from the EAF control device (typically a baghouse) to less than 3 percent opacity, as determined by EPA Method 9 of 40 CFR part 60, appendix A.

In both subparts, if the control device is equipped with a single stack, the owner or operator is required to install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS). The owner or operator must report each 6-minute average COMS reading of 3 percent or greater as an excess emission. A COMS is not required on any modular or multiple-stack fabric filter if opacity readings are taken at least once per day during a melting and refining period, in accordance with EPA Method 9.

The subparts also contain requirements for the EAF capture systems. However, those requirements are not being amended by today's action. As such, we do not discuss the capture system requirements here.

C. Why Are We Amending the New Source Performance Standards?

We are amending the NSPS in response to a petition to reopen the NSPS filed by the American Iron and Steel Institute (AISI), the Speciality Steel Industry of North America (SSINA), and the Steel Manufacturers Association (SMA) ("the Petitioner"). In the request to reopen, the Petitioner argues that COMS are not capable of accurately monitoring opacity emissions from an EAF shop at the 3 percent excess emission threshold level, and that the EAF NSPS should be amended to address the technological shortcomings associated with COMS. In making this argument, the Petitioner points to our recent revision (65 FR 48914, August 10, 2000) to performance specification 1 (PS–1) for COMS (40 CFR part 60, appendix B) in which we acknowledge that there is potential for measurement error associated with COMS readings. On October 16, 2002 (67 FR 64014), in response to the petition, we proposed amendments to the NSPS that would allow bag leak detection systems as an alternative monitoring option. More information on the industry petition can be found in the preamble to the proposed amendments.

Today's final rule amendments reflect our full consideration of the petition, including all of the public comments received. The petition to reopen is granted to the extent provided in today's final action adding an alternative to COMS for monitoring emissions from EAF control devices. The petition is denied in all other respects. For the reasons stated in the response to comments below, we have determined that the alternatives suggested by the Petitioner are inappropriate, and that other measures, including the bag leak detection system monitoring alternative finalized today, adequately address its concerns about potential measurement error.

III. Summary of the Final Amendments

A. What Is the New Alternative Monitoring Option?

The final rule amendments allow plants to use a bag leak detection system on all single stack fabric filters as an alternative monitoring option to COMS. Owners or operators are required to develop a site-specific monitoring plan describing how the system will be selected, installed, and operated, including how the alarm levels will be established. In the event a bag leak detection system alarm is triggered, the owner or operator must initiate corrective action to determine the cause of the alarm within 1 hour of the alarm and alleviate the cause of the alarm within 3 hours. An approved site-specific monitoring plan may allow more than 3 hours for alleviating a specified condition where an explanation is provided justifying a longer time period.

The owner or operator also must conduct an opacity observation at least once per day when the furnace is in the melting and refining period, in accordance with EPA Method 9 (40 CFR part 60, appendix A). All opacity observations greater than 3 percent opacity must be reported as a violation of the opacity standard. In addition, if the alarm on the bag leak detection system was not alarming during the time the opacity was observed to be greater than 3 percent, the alarm on the bag leak detection system must be lowered to a point that an alarm would have occurred during the observation.

B. What Editorial Corrections Are We Making?

Two typographical errors are corrected in the amendments. In 40 CFR 60.274(c) and in 40 CFR 60.274a(c), the references to paragraphs (b)(1) and (2) are corrected to refer to paragraph (b). The paragraphs (b)(1) and (2) of 40 CFR 60.274(c) and 40 CFR 60.274a(c) were incorporated into paragraph (b) during the last revision to the NSPS (64 FR 10105, March 2, 1999). In 40 CFR 60.274a(b), the reference to paragraph (d) is corrected to refer to paragraph (e).

In addition, 40 CFR 60.274a(d) and 40 CFR 60.274a(e) are revised to clarify that owners and operators may petition the Administrator to approve alternatives to the monitoring requirements specified in 40 CFR 60.274a(b), as well as alternatives to the monthly operational status inspections specified in 40 CFR 60.274a(d). These revisions do not change the rules requirements because owners and operators are currently allowed to petition for alternative monitoring requirements under 40 CFR 60.13(i) of the NSPS General Provisions (40 CFR part 60, subpart A).

IV. Response to Comments

We received a total of 20 comment letters on the proposed amendments from representatives of three industry trade associations, one State agency, one steelmaking company, the steelworkers labor union, three equipment vendors, and two private citizens. We offered to provide interested individuals the opportunity for oral presentations of data, views, or arguments concerning the proposed amendments, but a public hearing was not requested. Today's final rule amendments reflect our full consideration of all the comments received.

Comment: We received comments supporting bag leak detection systems as an alternative to COMS from two equipment vendors, representatives of three industry trade associations, and one steelmaker. Two vendors express support for bag leak detection systems based on comparative study results and the lower operation and maintenance costs. The industry commenters express support for this alternative monitoring system because of a reported potential for measurement error associated with COMS at levels below 10 percent opacity, which they believe is evidenced by the revisions to PS–1 for COMS (65 FR 48914, August 10, 2000).

We received comments opposing bag leak detection systems as an alternative to COMS from 11 members of one equipment vending firm, two private citizens, one State environmental agency, and representatives of the steelworker's union. These commenters do not agree that the proposed alternative is necessary because revisions to PS–1 (40 CFR part 60, appendix B) in EPA's 2002 "Conditional Performance Specification for Measurement 0–10% Opacity" (designed specifically for EAF) ensure accurate COMS measurements below 10 percent opacity. The conditional performance specification addresses the limitations of PS–1 and the technical problems described in the industry's study. In addition, a low-opacity COMS that meets PS–1 and the conditional performance specification has been installed and certified on EAF. The low-opacity COMS costs only 15 percent more than a standard COMS and is easy to use. One commenter also contends that EPA has not shown in the administrative record that steel mini-mills have been improperly burdened by enforcement actions based on erroneous opacity readings below 10 percent. Another stated that allowing the proposed alternative will increase emissions and noncompliance.

The commenters argue that plants cannot use bag leak detection systems to certify continuous compliance because they are not accurate enough and do not actually measure PM or opacity. In addition, Method 9 (40 CFR part 60, appendix B) cannot provide a reasonable check of bag leak detection systems because: (1) The method is good only at opacity levels of 7 to 8 percent; (2) COMS are necessary for some facilities where Method 9 is not applicable or accurate due to factors such as baghouse orientation or extreme southern latitudes, (3) the periodic readings are taken only once daily for 18 minutes during daylight hours and not during the operations that generate the most emissions, or (4) are subject to manipulation.

Response: We disagree with commenters that bag leak detectors are ineffective or inappropriate. We have required bag leak detection systems as monitoring systems in numerous national emission standards for hazardous air pollutants (NESHAP) developed under section 112 of the Clean Air Act (CAA). We are not aware of any States or EPA Regions with concerns about certifying continuous compliance for the numerous existing rules that utilize bag leak detection systems, and the commenters did not provide any specific information in support of their assertions. These systems have been demonstrated to be very effective at detecting leaks and bag failures on a continuing basis in many different applications. The systems provide timely information that can be used to reduce excess emissions that occur when unexpected leaks or failures occur.

Bag leak detection systems offer a viable and effective alternative to COMS for monitoring the performance of baghouses. While bag leak detection systems do not directly measure PM or opacity, they sense any increase in PM concentration at very low levels before emissions rise to a level that would result in observable opacity. Given the sensitivity of bag leak detection systems to changes in PM concentration, along with the daily Method 9 observations to verify the performance of the bag leak detection systems, allowing bag leak detections systems as an alternative to COMS will not increase emissions or noncompliance. In fact, the opposite is true. By requiring owners and operators to identify leaks quickly and to make prompt repairs, we expect facilities that elect to use the bag leak detection alternative will reduce emissions.

Upon further review of the appropriateness of bag leak detection systems for the final rules, we became aware that the proposed minimum sensitivity of 10 milligrams per actual cubic meter (0.0044 grains per actual cubic foot) was near the level of the PM standard (12 mg/dscm or 0.0052 gr/dscf). However, based on consultation with vendors of bag leak detections systems, it was determined that standard bag leak detections systems are easily capable of measuring baseline emissions of 1 milligram per actual cubic meter or lower. As a result, we are lowering the minimum sensitivity to 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot). This change does not represent a significant departure from our proposed amendments because it does not affect the selection or cost of the bag leak detection systems available to owners or operators, but merely provides a more accurate representation of the minimum sensitivity of existing bag leak detection systems.

We disagree that Method 9 observations are inadequate to verify the performance of the bag leak detection systems. Although the human eye may not be able to distinguish opacity to the nearest 1 percent opacity, Method 9 observations were used as a basis for the 3 percent opacity limit. Method 9 involves 15 second opacity readings that are recorded at discrete values to the nearest 5 percent opacity, *i.e.*, values of either 0, 5, 10, or 15 percent, etc. Over a 6-minute period, Method 9 produces 24 readings that are used to develop the 6-minute average values. Method 9 readings were used to develop the original 3 percent opacity standard and continues to be the performance test method for determining compliance identified for these final rules as well as many others for measurement of opacity. As such, the proposed daily Method 9 observations are directly applicable and appropriate for the verification of the performance of the bag leak detection systems (as well as their direct use to assess compliance).

We do not agree that the commenter's concerns about limitations on the times that Method 9 may be conducted necessitate the use of COMS. Method 9 and 40 CFR 60.273(c) and 40 CFR 60.273a(c) specify the conditions under which the tests are to be conducted. Owners and operators must schedule and conduct the daily Method 9 reading such that these conditions are met. We do not know of any EAF facility that would be unable to meet the Method 9 requirements due to baghouse orientation and extreme southern latitude, and the commenter did not provide any specific information in support of their assertions. Also, the requirement to perform the Method 9 observation during melting and refining is consistent with the existing requirements for Method 9 observations on EAF stacks that are not equipped with COMS (40 CFR 60.273(c), 60.273a(c), 60.275(i) and 60.275a(i)).

The availability of low opacity COMS also does not warrant withholding bag leak detection systems as an alternative monitoring option. Although the installation and certification of new low-opacity COMS technology and the development of the conditional performance specification appear promising, additional steps are needed in the process before we can require their application. The conditional performance specification still must be approved as an alternative method or a revision to PS–1 before a source may use it to meet Federal requirements under 40 CFR part 60, 61, or 63. During that process, the specification is potentially subject to change based on the review of additional validation studies or on public comments as part of the process for adoption as an EPA test method or as a revision to PS–1. Nonetheless, an owner or operator who would prefer to use a low-opacity COMS could install a low-opacity COMS and certify it using PS–1, or apply to certify the low opacity COMS based on the conditional performance specification as an alternative monitoring option as allowed under the NSPS General Provisions (40 CFR part 60, appendix A).

Based on a review of public comments, we maintain that the bag leak detection systems provide a reasonable alternative to the COMS requirements.

Comment: Two industry commenters state that the bag leak detection system alternative does not resolve the potential measurement error associated with COMS readings at the 3 percent opacity level and thus does not resolve the petition to reopen the NSPS. The commenters cite statements in the rulemaking for PS–1 regarding the technological limitations of COMS, including a comment by an American Society for Testing and Materials (ASTM) representative that the ASTM standard for COMS (ASTM D6216–98), which is incorporated in PS–1, ensures accurate COMS measurements only at sources with opacity limits of 10 percent or greater. They also cite EPA's estimate of the upper range of potential measurement error of 4 percent opacity, and an industry study finding that COMS complying with PS–1 requirements have a potential error band of 7.5 percent.

The commenters stated that inaccurate data results in negative legal implications, such as exposure to inappropriate enforcement actions, hurdles to certifications of continuous compliance in the title V permitting program, and the triggering of additional excess emissions reports for false positive COMS readings. One commenter adds that false positive readings from COMS have occurred, as evidenced by simultaneous information from both COMS and Method 9 readings. The commenters stated that the proposed option does not resolve the industry's petition because it does not address the COMS error band issue. Not all facilities affected by the error band issue can replace COMS with bag leak detection systems due to costs, permit requirements, and the reluctance of EPA Regional Offices to approve the change. They request that EPA raise the excess reporting threshold to account for the error band, acknowledge that the COMS data within the error band are not credible evidence of opacity violations, or eliminate the COMS requirement in its entirety.

One commenter suggests that EPA retain the COMS requirements but require plants to report only the data that exceeds 10 percent opacity to address the error band issue. Opacity data less than 10 percent should not be recorded or reported.

Response: The alternatives suggested by the commenters do not provide adequate assurance and documentation that the opacity standard is being continuously maintained. Raising the excess reporting threshold would preclude the permitting authority and the public from obtaining information on any opacity exceedances falling below the new higher threshold (as high as 10 percent under the commenters' view) and thus undermine accountability to the 3 percent opacity standard. Eliminating the COMS requirement would result in the wholesale loss of continuous opacity measurements, even where exceedances are far above the potential error band.

The revisions to PS–1 explained that it was not appropriate to limit the applicability of PS–1 based on the level of the emission limit that would be measured. We determined that PS–1 should acknowledge the uncertainty associated with COMS measurements below 10 percent opacity and allow for consideration of the potential error (through statistical procedures or otherwise) when evaluating compliance with opacity standards below 10 percent. As commenters acknowledge,

EPA conducted a very conservative analysis of the upper range of potential measurement error that may be associated with COMS meeting PS–1 and found the upper range of potential measurement error to be about 4 percent. We also noted that a "properly operating and aligned COMS should experience measurement error significantly less than this magnitude." Thus, instead of broadly limiting the applicability of COMS, any uncertainty should be addressed on a case-by-case basis.

We note that while COMS is the required monitoring method (in the absence of a source choosing the alternative monitoring option finalized today), Method 9 remains the performance test method and, as such, is the benchmark against which other data are compared in determining source compliance.[1] If the company believes the COMS data are not credible evidence of an opacity violation, it may dispute the materiality of such data in its compliance certification or excess emissions report.[2] It may also challenge the relevance and accuracy of the COMS data in a judicial or administrative tribunal.[3] Thus, it is not necessary or appropriate to make a broad determination that COMS data within the potential error band are not credible evidence of opacity violations.

In addition, the bag leak detection system alternative provides owners or operators who are concerned with the accuracy of COMS measurements the option to use bag leak detection systems instead of COMS. Case-by-case approval of this alternative monitoring method by EPA Regional Offices will no longer be necessary after the alternative is incorporated into the NSPS through today's final rule amendments.

Comment: Comments from the industry trade associations support the proposed alternative but oppose certain provisions. They suggest that: (1) Facilities should be allowed 1 hour (rather than 30 minutes) to initiate procedures to determine the cause of an alarm, (2) the proposed 3-hour limit for alleviating the cause of an alarm be replaced with "as soon as practicable" or "within a reasonable time" to account for scenarios that may take longer than 3 hours to identify and fix, and (3) facilities should not have to receive advance approval of their site-specific monitoring plan.

Response: A key and necessary component of the bag leak detection system alternative is the requirement to initiate corrective action and alleviate the cause of alarms as soon as possible. Providing specific time requirements makes the standard much clearer for both the regulators and the regulated community. Based on our experience with baghouses, bag leak detectors, and the various corrective actions that may be required, we determined that the 30-minute period to initiate corrective action was insufficient and should be revised to 1 hour. This change is consistent with the bag leak detection requirements we have promulgated in other rules.

We agree that the cause of the alarm should be alleviated as soon as practicable; however, the 3-hour limit is reasonable and necessary to ensure that corrective action needed to alleviate the cause of the alarm be taken to ensure timely action and to protect the environment. Most causes of an alarm can be fixed within the 3-hour limit. For example, modern baghouses have multiple compartments so that one compartment can be quickly isolated (*i.e.*, taken out of service) to perform maintenance or to isolate a leaking bag without requiring the process to be shut down. Nonetheless, we have added a provision to the final rule amendments stating that, as part of the site-specific monitoring plan, the Administrator or delegated authority may approve such additional time as necessary to ensure corrective action as expeditiously as practicable where the owner or operator identifies the condition that could lead to an alarm and adequately explains why the 3-hour limit for the condition is not feasible. This adequately addresses those few scenarios where more than 3 hours is necessary to alleviate the cause of the alarm.

We are retaining the requirement to receive advance approval of site-specific monitoring plans. Pre-approval of the monitoring plans serves several purposes. First, it provides EPA an indication of which monitoring method the facility will use. Second, it ensures that the monitors will be properly installed for all applicable emission points. In addition, it provides the owner or operator some assurance that the proposed monitoring approach will be satisfactory and may avoid unnecessary expenditures if the monitoring approach was found to be inadequate after it was implemented.

Comment: One commenter proposed a change to 40 CFR 60.723(e)(6)(ii), which reads: "opacity over zero percent would require an adjustment of the bag leak detection system alarm levels." The commenter stated this should read "over three percent."

Response: As discussed above, a Method 9 opacity observation is composed of 24 individual, 15 second opacity readings. Each individual reading is recorded in 5 percent increments. As such, any visible emissions would be recorded as 5 percent opacity or greater. Baghouses in good working condition control emissions to below the level that would result in visible emissions (*i.e.*, zero percent). If visible emissions are observed from a baghouse, it is an indication that a leak has occurred, and the bag leak detection system should be adjusted to ensure the alarm sounds at that point or below.

Comment: One commenter stated the proposed amendment improperly relaxes monitoring requirements by allowing excursions from bag leak detection system operational parameters for up to 3 percent of facility operating hours. The commenter stated that this provision does not ensure continuous compliance with the opacity and particulate emission limits.

On the other hand, comments from industry trade associations oppose the 3 percent limit on alarms because: (1) It undermines the purpose of bag leak detection systems, which is to detect emissions before they become exceedances; and (2) the limit assumes that alarms equate to exceedances or that the alarms indicate poor operation. The number of alarms may reflect only how low a facility sets the alarm level, and the operating limit serves to increase the stringency of the emission limit. Instead, the commenter suggests that EPA adopt an alarm threshold above which plants would be required to implement a quality improvement plan or adopt a threshold of 5 percent as it has done in other rules. The proposed amendments should also describe more clearly how operating time is to be calculated and confirm what operations would constitute a startup, shutdown, or malfunction.

Response: We reconsidered the 3 percent limit on alarms for baghouse leak detection system alarms as applied to EAF. We have no data indicating that the 3 percent limit on alarms has been applied to these operations, and we have no firm basis for determining what level, if any, might be appropriate for these operations. We agree that the

[1] *See* Credible Evidence Revisions (62 FR 8314, February 24, 1997) ("the reference tests remain the benchmark against which * * * other information will be evaluated.").

[2] *See Natural Resources Defense Council* v. *EPA*, 194 F.3d 130, 138 (D.C. Cir. 1999) ("[N]othing precludes an owner from adding a caveat to its certification to the effect that, while it is providing other evidence which EPA might find material, the submitter disputes its materiality and reserves the right to challenge the use of the evidence in court.").

[3] *See* 62 FR at 8322; *Grand Canyon Trust* v. *Public Serv. Co. of New Mexico*, 294 F. Supp. 2d 1246 (D.N.M. 2003).

purpose of bag leak detection systems is to detect emissions before they become exceedances. For these reasons, we have dropped the 3 percent limit on alarms. However, it is important that corrective action be initiated promptly; consequently, we require that corrective actions be initiated within 1 hour of an alarm to ensure baghouses are well maintained and operated properly on a continuing basis. Excessive alarms are effectively limited by the general duty under 40 CFR 60.11(d) to maintain and operate air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions.

In response to the comments, we have not included the following proposed provisions in the final rule amendments: (1) The definition of "operating time" in 40 CFR 60.271(p) and 60.271a, (2) the proposed operating limit in 40 CFR 63.273(g) and 63.273a(g), (3) associated provisions in 40 CFR 63.273(h) and 63.273a(h) for determining how to calculate the percentage of time the alarm sounds, and (4) associated recordkeeping and recording requirements in 40 CFR 63.276(e) and (f) and 40 CFR 63.276a(h)(4) and (i).

Comment: One commenter asks EPA to specify whether bag leak detection system records must be reported according to the requirements in 40 CFR 70.6(c) and 71.6(c) and whether the records may be used to establish violations under the NSPS credible evidence requirements in 40 CFR 60.11. Should EPA remove the 3 percent allowance for operation of the EAF and fume collection system while the bag leak detection system indicates bag leaks or pressure loss, the amendments should clarify that any system failures that cause an alarm are evidence of a violation.

Response: With regard to recordkeeping and reporting requirements under 40 CFR part 70, 40 CFR 70.6(c) and 71.6(c) clearly require that title V permits include recordkeeping and reporting provisions covering the bag leak detection system records in this NSPS (40 CFR 60.273(c), 60.273a(c), 60.276(e), and 60.276a(h)). The part 70 regulations state that title V permits must contain recordkeeping and reporting requirements consistent with 40 CFR 70.6(a)(3) and 71.6(a)(3), respectively. Those provisions further provide that the permit must incorporate "all applicable recordkeeping requirements, including "[r]ecords of required monitoring information," and "all applicable reporting requirements." They also require "[s]ubmittal of reports of any required monitoring at least every six months."

Whether such records establish violations of the opacity limit will vary depending on the circumstances presented. As stated previously, the purpose of bag leak detection systems is to detect emissions before they become exceedances. Whether a particular alarm or exceedance can be used as credible evidence of such a violation depends upon the facts presented in each case. Additionally, as we stated in the preamble to the credible evidence rule, "what evidence is credible and admissible will be determined by * * * taking into account how the evidence was gathered and the specifics of the emission standard and any associated reference method." (62 FR 8314, 8323, February 24, 1997).[4]

Independent of whether a particular alarm or exceedance is credible evidence of a violation of the opacity limit, sources have a duty to comply with the baghouse leak detection system monitoring requirements where a source chooses such monitoring as an alternative to COMS, and failure to comply with the monitoring requirements could give rise to an enforcement action under section 113(a)(3) or section 304(a) of the CAA.

Comment: Comments from industry trade associations do not oppose the editorial corrections to 40 CFR 60.274(c) and 60.274a(c), but the commenter questions why the proposed wording of the regulatory text differs from the existing rule. The existing rule was amended on October 17, 2000, to read:

(c) When the owner or operator of an affected facility is required to demonstrate compliance with the standards under § 63.272(a)(3) *and at any other time that the Administrator may require* (under section 114 of the CAA, as amended) either * * *.

The proposed regulatory text reads "at any other time the Administrator may require *that*". The industry commenters believe the location of the word "that" could change the meaning of the paragraph. The paragraph could be interpreted as allowing the Administrator to choose which of the three monitoring options a facility must follow. To clarify this issue, the word "that" should follow "at any other time."

Response: We did not intend to alter the placement of the word "that" in 40 CFR 60.274(c) and 60.274a(c). We have revised the placement of the word "that" in the final rule amendment to follow "at any other time," as suggested by the commenter, to clarify that the Administrator does not choose which of the three monitoring options a facility must use.

[4] The Agency further explained that it would not issue lists of presumptively credible evidence, explaining that "both judicial and administrative tribunals routinely make determinations concerning the admissibility and weight of evidence on a case-by-case basis." (*See* 62 FR 8316.) Such case-by-case evaluations would apply to data generated by bag leak detection systems.

V. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the EPA must determine whether the regulatory action is "significant" and therefore subject to review by the Office of Management and Budget (OMB) and the requirements of the Executive Order. The Executive Order defines a "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 entitlement, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

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

It has been determined that the final rule amendments are not a "significant regulatory action" under the terms of Executive Order 12866 and are, therefore, not subject to OMB review.

B. Paperwork Reduction Act

The information collection requirements in the final rule amendments have been submitted for approval to 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 in the final rule amendments are based on notification, recordkeeping, and reporting requirements in the NSPS General Provisions (40 CFR part 60, subpart A), which are mandatory for all operators subject to NSPS. The records and reports required by these rule amendments are necessary for EPA to: (1) Identify new, modified, or reconstructed sources subject to the

rule; (2) ensure that the rule requirements are being properly applied; and (3) ensure that the emission control devices are being properly operated and maintained on a continuous basis. Based on the reported information, EPA can decide which plants, records, or processes should be inspected. The recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies in 40 CFR part 2, subpart B.

The annual increase to monitoring, recordkeeping, and reporting burden for the final rule amendments are estimated at 1,750 labor hours at a total cost of $96,145 nationwide, and the annual average increase in burden is 175 labor hours and $9,615 per source. The estimate of the increase in annual monitoring, recordkeeping, and reporting annual cost in the final rule amendment is higher than the estimate made in the proposal by $34,878, which is due to the use of a higher cost of labor estimate ($26.16/hr, $54.94/hr including overhead) than was used in the proposal ($16.67/hr, $35.01/hr including overhead). We estimate that there will be no increase in the annualized capital costs due to the final rule amendments. We estimate that the annualized costs associated with purchasing and installing a bag leak detection system are equal to the offsetting annualized cost savings associated with the discontinued use and periodic replacement of a COMS. In making the estimates, it was assumed that ten existing facilities currently required to install and operate COMS would elect to use the proposed alternative monitoring option. The cost estimates reflect increased costs associated with the installation and operation of a bag leak detection system and with daily opacity observations partially offset by the cost savings from no longer having to operate and maintain a COMS.

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 purpose 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 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 number for EPA's regulations in 40 CFR part 60 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 these final rule amendments.

C. Regulatory Flexibility Analysis

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with the final rule amendments. For the purposes of assessing the economic impact of today's final rule amendments on small entities, small entity is defined as: (1) A small business according to U.S. Small Business Administration size standards for NAICS code 331111 having no more than 1,000 employees; (2) a small government jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and that is not dominant in its field.

After considering the economic impacts of today's final rule amendments on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant adverse economic impact on small entities since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives "which minimize any significant economic impact of the proposed rule on small entities" (5 U.S.C. 603 and 604). Thus, an agency may conclude that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic impact on all of the small entities subject to the rule.

The final rule amendments provide a new compliance option for all facilities (large or small) that is designed to increase flexibility. We have, therefore, concluded that today's final rule amendments will relieve regulatory burden for all small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, the EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires the EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least-burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows the EPA to adopt an alternative other than the least-costly, most cost-effective, or least-burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before the EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

The EPA has determined that the final rule amendments do not contain a Federal mandate that may result in estimated costs of $100 million or more to either State, local, or tribal governments, in the aggregate, or to the private sector in any 1 year. The maximum total annualized costs of the final rule amendments for any year is estimated at less than $97,000. Thus, today's final rule amendments are not subject to sections 202 and 205 of the UMRA. The EPA has also determined

that the final rule amendments contain no regulatory requirements that might significantly or uniquely affect small governments because they contain no requirements that apply to such governments or impose obligations upon them. Thus, today's final rule amendments are not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

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

The final rule amendments do not have federalism implications. They will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. None of the affected facilities are owned or operated by State governments, and the requirements of the final rule amendments will not supersede State regulations that are more stringent. Thus, Executive Order 13132 does not apply to the final rule amendments.

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

Executive Order 13175 (65 FR 67249, November 9, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input in the development of regulatory policies on matters that have tribal implications."

The final rule amendments do not have tribal implications, as specified in Executive Order 13175. They will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes. No tribal governments own or operate an affected source. Thus, Executive Order 13175 does not apply to the final rule amendments.

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

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

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. The final rule amendments are not subject to Executive Order 13045 because they are based on control technology and not on health or safety risks. No children's risk analysis was performed because the action only provides EAF owners and operators with an alternative monitoring option. Furthermore, the final rule amendments have been determined not to be "economically significant" as defined under Executive Order 12866.

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

The final rule amendments are not subject to Executive Order 13211 (66 FR 28355, May 22, 2001) because they are not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. No. 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to the OMB, with explanations when the Agency decides not to use available and applicable voluntary consensus standards. The final rule amendments do not involve voluntary consensus standards.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA has submitted a report containing the final rule amendments and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to the publication of the final rule amendments in today's **Federal Register**. The final rule amendments are not a "major rule" as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

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

Dated: February 14, 2005.

Stephen L. Johnson,

Acting Administrator.

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

PART 60—[AMENDED]

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

Subpart AA—[Amended]

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

■ 2. Section 60.271 is amended by adding new paragraph (o) to read as follows:

§ 60.271 Definitions.

* * * * *

(o) *Bag leak detection system* means a system that is capable of continuously monitoring relative particulate matter (dust) loadings in the exhaust of a baghouse to detect bag leaks and other conditions that result in increases in particulate loadings. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, electrodynamic, light scattering, light transmittance, or other effect to continuously monitor relative particulate matter loadings.

■ 3. Section 60.273 is amended by revising paragraph (c) and adding new

paragraphs (e), (f), and (g) to read as follows:

§ 60.273 Emission monitoring.

* * * * *

(c) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) is not required on any modular, multi-stack, negative-pressure or positive-pressure fabric filter if observations of the opacity of the visible emissions from the control device are performed by a certified visible emission observer; or on any single-stack fabric filter if visible emissions from the control device are performed by a certified visible emission observer and the owner installs and continuously operates a bag leak detection system according to paragraph (e) of this section. Visible emission observations shall be conducted at least once per day for at least three 6-minute periods when the furnace is operating in the melting and refining period. All visible emissions observations shall be conducted in accordance with Method 9 of appendix A to this part. If visible emissions occur from more than one point, the opacity shall be recorded for any points where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of the visible emission, only one set of three 6-minute observations will be required. In that case, the Method 9 observations must be made for the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of the emission limit specified in § 60.272(a).

* * * * *

(e) A bag leak detection system must be installed and continuously operated on all single-stack fabric filters if the owner or operator elects not to install and operate a continuous opacity monitoring system as provided for under paragraph (c) of this section. In addition, the owner or operator shall meet the visible emissions observation requirements in paragraph (c) of this section. The bag leak detection system must meet the specifications and requirements of paragraphs (e)(1) through (8) of this section.

(1) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(2) The bag leak detection system sensor must provide output of relative particulate matter loadings and the owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (*e.g.*, using a strip chart recorder or a data logger.)

(3) The bag leak detection system must be equipped with an alarm system that will sound when an increase in relative particulate loading is detected over the alarm set point established according to paragraph (e)(4) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(4) For each bag leak detection system required by paragraph (e) of this section, the owner or operator shall develop and submit to the Administrator or delegated authority, for approval, a site-specific monitoring plan that addresses the items identified in paragraphs (i) through (v) of this paragraph (e)(4). For each bag leak detection system that operates based on the triboelectric effect, the monitoring plan shall be consistent with the recommendations contained in the U.S. Environmental Protection Agency guidance document "Fabric Filter Bag Leak Detection Guidance" (EPA–454/R–98–015). The owner or operator shall operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. The plan shall describe:

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system including quality assurance procedures;

(iv) How the bag leak detection system will be maintained including a routine maintenance schedule and spare parts inventory list; and

(v) How the bag leak detection system output shall be recorded and stored.

(5) The initial adjustment of the system shall, at a minimum, consist of establishing the baseline output by adjusting the sensitivity (range) and the averaging period of the device, and establishing the alarm set points and the alarm delay time (if applicable).

(6) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided for in paragraphs (e)(6)(i) and (ii) of this section.

(i) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects including temperature and humidity according to the procedures identified in the site-specific monitoring plan required under paragraphs (e)(4) of this section.

(ii) If opacities greater than zero percent are observed over four consecutive 15-second observations during the daily opacity observations required under paragraph (c) of this section and the alarm on the bag leak detection system does not sound, the owner or operator shall lower the alarm set point on the bag leak detection system to a point where the alarm would have sounded during the period when the opacity observations were made.

(7) For negative pressure, induced air baghouses, and positive pressure baghouses that are discharged to the atmosphere through a stack, the bag leak detection sensor must be installed downstream of the baghouse and upstream of any wet scrubber.

(8) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(f) For each bag leak detection system installed according to paragraph (e) of this section, the owner or operator shall initiate procedures to determine the cause of all alarms within 1 hour of an alarm. Except as provided for in paragraph (g) of this section, the cause of the alarm must be alleviated within 3 hours of the time the alarm occurred by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(1) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(2) Sealing off defective bags or filter media;

(3) Replacing defective bags or filter media or otherwise repairing the control device;

(4) Sealing off a defective baghouse compartment;

(5) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(6) Shutting down the process producing the particulate emissions.

(g) In approving the site-specific monitoring plan required in paragraph (e)(4) of this section, the Administrator or delegated authority may allow owners or operators more than 3 hours to alleviate specific conditions that cause an alarm if the owner or operator identifies the condition that could lead to an alarm in the monitoring plan,

adequately explains why it is not feasible to alleviate the condition within 3 hours of the time the alarm occurred, and demonstrates that the requested additional time will ensure alleviation of the condition as expeditiously as practicable.

■ 4. Section 60.274 is amended by revising the first sentence of paragraph (c) to read as follows:

§ 60.274 Monitoring of operations.

* * * * *

(c) When the owner or operator of an affected facility is required to demonstrate compliance with the standards under § 60.272(a)(3) and at any other time that the Administrator may require (under section 114 of the CAA, as amended) either: the control system fan motor amperes and all damper positions, the volumetric flow rate through each separately ducted hood, or the volumetric flow rate at the control device inlet and all damper positions shall be determined during all periods in which a hood is operated for the purpose of capturing emissions from the affected facility subject to paragraph (b) of this section. * * *

* * * * *

■ 5. Section 60.275 is amended by revising paragraph (i) to read as follows:

§ 60.275 Test methods and procedures.

* * * * *

(i) If visible emissions observations are made in lieu of using a continuous opacity monitoring system, as allowed for by § 60.273(c), visible emission observations shall be conducted at least once per day for at least three 6-minute periods when the furnace is operating in the melting and refining period. All visible emissions observations shall be conducted in accordance with Method 9. If visible emissions occur from more than one point, the opacity shall be recorded for any points where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of the visible emission, only one set of three 6-minute observations will be required. In that case, the Method 9 observations must be made for the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of the emission limit specified in § 60.272(a).

* * * * *

■ 6. Section 60.276 is amended by adding new paragraph (e) to read as follows:

§ 60.276 Recordkeeping and reporting requirements.

* * * * *

(e) The owner or operator shall maintain the following records for each bag leak detection system required under § 60.273(e):

(1) Records of the bag leak detection system output;

(2) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(3) An identification of the date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 3 hours of the alarm.

Subpart AAa—[Amended]

■ 7. Section 60.271a is amended by adding, in alphabetical order, a definition for "Bag leak detection system" as follows:

§ 60.271a Definitions.

* * * * *

Bag leak detection system means a system that is capable of continuously monitoring relative particulate matter (dust) loadings in the exhaust of a baghouse to detect bag leaks and other conditions that result in increases in particulate loadings. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, electrodynamic, light scattering, light transmittance, or other effect to continuously monitor relative particulate matter loadings.

* * * * *

■ 8. Section 60.273a is amended by revising paragraph (c) and adding new paragraphs (e) and (f) to read as follows:

§ 60.273a Emission monitoring.

* * * * *

(c) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) is not required on any modular, multi-stack, negative-pressure or positive-pressure fabric filter if observations of the opacity of the visible emissions from the control device are performed by a certified visible emission observer; or on any single-stack fabric filter if visible emissions from the control device are performed by a certified visible emission observer and the owner installs and continuously operates a bag leak detection system according to paragraph (e) of this section. Visible emission observations shall be conducted at least once per day for at least three 6-minute periods when the furnace is operating in the melting and refining period. All visible emissions observations shall be conducted in accordance with Method 9. If visible emissions occur from more than one point, the opacity shall be recorded for any points where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of the visible emission, only one set of three 6-minute observations will be required. In that case, the Method 9 observations must be made for the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of the emission limit specified in § 60.272a(a).

* * * * *

(e) A bag leak detection system must be installed and continuously operated on all single-stack fabric filters if the owner or operator elects not to install and operate a continuous opacity monitoring system as provided for under paragraph (c) of this section. In addition, the owner or operator shall meet the visible emissions observation requirements in paragraph (c) of this section. The bag leak detection system must meet the specifications and requirements of paragraphs (e)(1) through (8) of this section.

(1) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(2) The bag leak detection system sensor must provide output of relative particulate matter loadings and the owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (*e.g.*, using a strip chart recorder or a data logger.)

(3) The bag leak detection system must be equipped with an alarm system that will sound when an increase in relative particulate loading is detected over the alarm set point established according to paragraph (e)(4) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(4) For each bag leak detection system required by paragraph (e) of this section,

the owner or operator shall develop and submit to the Administrator or delegated authority, for approval, a site-specific monitoring plan that addresses the items identified in paragraphs (i) through (v) of this paragraph (e)(4). For each bag leak detection system that operates based on the triboelectric effect, the monitoring plan shall be consistent with the recommendations contained in the U.S. Environmental Protection Agency guidance document "Fabric Filter Bag Leak Detection Guidance" (EPA–454/R–98–015). The owner or operator shall operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. The plan shall describe the following:

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system including quality assurance procedures;

(iv) How the bag leak detection system will be maintained including a routine maintenance schedule and spare parts inventory list; and

(v) How the bag leak detection system output shall be recorded and stored.

(5) The initial adjustment of the system shall, at a minimum, consist of establishing the baseline output by adjusting the sensitivity (range) and the averaging period of the device, and establishing the alarm set points and the alarm delay time (if applicable).

(6) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided for in paragraphs (e)(6)(i) and (ii) of this section.

(i) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects including temperature and humidity according to the procedures identified in the site-specific monitoring plan required under paragraphs (e)(4) of this section.

(ii) If opacities greater than zero percent are observed over four consecutive 15-second observations during the daily opacity observations required under paragraph (c) of this section and the alarm on the bag leak detection system does not sound, the owner or operator shall lower the alarm set point on the bag leak detection system to a point where the alarm would have sounded during the period when the opacity observations were made.

(7) For negative pressure, induced air baghouses, and positive pressure baghouses that are discharged to the atmosphere through a stack, the bag leak detection sensor must be installed downstream of the baghouse and upstream of any wet scrubber.

(8) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(f) For each bag leak detection system installed according to paragraph (e) of this section, the owner or operator shall initiate procedures to determine the cause of all alarms within 1 hour of an alarm. Except as provided for under paragraph (g) of this section, the cause of the alarm must be alleviated within 3 hours of the time the alarm occurred by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to, the following:

(1) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(2) Sealing off defective bags or filter media;

(3) Replacing defective bags or filter media or otherwise repairing the control device;

(4) Sealing off a defective baghouse compartment;

(5) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; and

(6) Shutting down the process producing the particulate emissions.

(g) In approving the site-specific monitoring plan required in paragraph (e)(4) of this section, the Administrator or delegated authority may allow owners or operators more than 3 hours to alleviate specific conditions that cause an alarm if the owner or operator identifies the condition that could lead to an alarm in the monitoring plan, adequately explains why it is not feasible to alleviate the condition within 3 hours of the time the alarm occurred, and demonstrates that the requested additional time will ensure alleviation of the condition as expeditiously as practicable.

■ 9. Section 60.274a is amended by revising the first sentence of paragraph (b), revising the first sentence of paragraph (c), revising the first sentence of paragraph (d), and revising paragraph (e) to read as follows:

§ 60.274a Monitoring of operations.

* * * * *

(b) Except as provided under paragraph (e) of this section, the owner or operator subject to the provisions of this subpart shall check and record on a once-per-shift basis the furnace static pressure (if DEC system is in use, and a furnace static pressure gauge is installed according to paragraph (f) of this section) and either: check and record the control system fan motor amperes and damper position on a once-per-shift basis; install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate through each separately ducted hood; or install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and check and record damper positions on a once-per-shift basis.* * *

(c) When the owner or operator of an affected facility is required to demonstrate compliance with the standards under § 60.272a(a)(3) and at any other time that the Administrator may require (under section 114 of the CAA, as amended) either: the control system fan motor amperes and all damper positions, the volumetric flow rate through each separately ducted hood, or the volumetric flow rate at the control device inlet and all damper positions shall be determined during all periods in which a hood is operated for the purpose of capturing emissions from the affected facility subject to paragraph (b) of this section. * * *

(d) Except as provided under paragraph (e) of this section, the owner or operator shall perform monthly operational status inspections of the equipment that is important to the performance of the total capture system (*i.e.*, pressure sensors, dampers, and damper switches). * * *

(e) The owner or operator may petition the Administrator to approve any alternative to either the monitoring requirements specified in paragraph (b) of this section or the monthly operational status inspections specified in paragraph (d) of this section if the alternative will provide a continuous record of operation of each emission capture system.

* * * * *

■ 10. Section 60.276a is amended by adding new paragraph (h) to read as follows:

§ 60.276a Recordkeeping and reporting requirements.

* * * * *

(h) The owner or operator shall maintain the following records for each bag leak detection system required under § 60.273a(e):

(1) Records of the bag leak detection system output;

(2) Records of bag leak detection system adjustments, including the date

and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(3) An identification of the date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 3 hours of the alarm.

* * * * *

[FR Doc. 05–3360 Filed 2–18–05; 8:45 am]
BILLING CODE 6560–50–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

44 CFR Part 64

[Docket No. FEMA–7867]

Suspension of Community Eligibility

AGENCY: Federal Emergency Management Agency, Emergency Preparedness and Response Directorate, Department of Homeland Security.

ACTION: Final rule.

SUMMARY: This rule identifies communities, where the sale of flood insurance has been authorized under the National Flood Insurance Program (NFIP), that are scheduled for suspension on the effective dates listed within this rule because of noncompliance with the floodplain management requirements of the program. If the Federal Emergency Management Agency (FEMA) receives documentation that the community has adopted the required floodplain management measures prior to the effective suspension date given in this rule, the suspension will not occur and a notice of this will be provided by publication in the **Federal Register** on a subsequent date.

DATES: The effective date of each community's scheduled suspension is the third date ("Susp.") listed in the third column of the following tables.

ADDRESSES: If you wish to determine whether a particular community was suspended on the suspension date, contact the appropriate FEMA Regional Office or the NFIP servicing contractor.

FOR FURTHER INFORMATION CONTACT: Michael M. Grimm, Mitigation Division, 500 C Street, SW., Room 412, Washington, DC 20472, (202) 646–2878.

SUPPLEMENTARY INFORMATION: The NFIP enables property owners to purchase flood insurance which is generally not otherwise available. In return, communities agree to adopt and administer local floodplain management aimed at protecting lives and new construction from future flooding. Section 1315 of the National Flood Insurance Act of 1968, as amended, 42 U.S.C. 4022, prohibits flood insurance coverage as authorized under the National Flood Insurance Program, 42 U.S.C. 4001 *et seq.*; unless an appropriate public body adopts adequate floodplain management measures with effective enforcement measures. The communities listed in this document no longer meet that statutory requirement for compliance with program regulations, 44 CFR part 59 *et seq.* Accordingly, the communities will be suspended on the effective date in the third column. As of that date, flood insurance will no longer be available in the community. However, some of these communities may adopt and submit the required documentation of legally enforceable floodplain management measures after this rule is published but prior to the actual suspension date. These communities will not be suspended and will continue their eligibility for the sale of insurance. A notice withdrawing the suspension of the communities will be published in the **Federal Register**.

In addition, the Federal Emergency Management Agency has identified the special flood hazard areas in these communities by publishing a Flood Insurance Rate Map (FIRM). The date of the FIRM if one has been published, is indicated in the fourth column of the table. No direct Federal financial assistance (except assistance pursuant to the Robert T. Stafford Disaster Relief and Emergency Assistance Act not in connection with a flood) may legally be provided for construction or acquisition of buildings in the identified special flood hazard area of communities not participating in the NFIP and identified for more than a year, on the Federal Emergency Management Agency's initial flood insurance map of the community as having flood-prone areas (section 202(a) of the Flood Disaster Protection Act of 1973, 42 U.S.C. 4106(a), as amended). This prohibition against certain types of Federal assistance becomes effective for the communities listed on the date shown in the last column. The Administrator finds that notice and public comment under 5 U.S.C. 553(b) are impracticable and unnecessary because communities listed in this final rule have been adequately notified.

Each community receives a 6-month, 90-day, and 30-day notification letter addressed to the Chief Executive Officer that the community will be suspended unless the required floodplain management measures are met prior to the effective suspension date. Since these notifications have been made, this final rule may take effect within less than 30 days.

National Environmental Policy Act. This rule is categorically excluded from the requirements of 44 CFR part 10, Environmental Considerations. No environmental impact assessment has been prepared.

Regulatory Flexibility Act. The Administrator has determined that this rule is exempt from the requirements of the Regulatory Flexibility Act because the National Flood Insurance Act of 1968, as amended, 42 U.S.C. 4022, prohibits flood insurance coverage unless an appropriate public body adopts adequate floodplain management measures with effective enforcement measures. The communities listed no longer comply with the statutory requirements, and after the effective date, flood insurance will no longer be available in the communities unless they take remedial action.

Regulatory Classification. This final rule is not a significant regulatory action under the criteria of section 3(f) of Executive Order 12866 of September 30, 1993, Regulatory Planning and Review, 58 FR 51735.

Paperwork Reduction Act. This rule does not involve any collection of information for purposes of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*

Executive Order 12612, Federalism. This rule involves no policies that have federalism implications under Executive Order 12612, Federalism, October 26, 1987, 3 CFR, 1987 Comp.; p. 252.

Executive Order 12778, Civil Justice Reform. This rule meets the applicable standards of section 2(b)(2) of Executive Order 12778, October 25, 1991, 56 FR 55195, 3 CFR, 1991 Comp.; p. 309.

List of Subjects in 44 CFR Part 64

Flood insurance, Floodplains.

■ Accordingly, 44 CFR part 64 is amended as follows:

PART 64—[AMENDED]

■ 1. The authority citation for part 64 continues to read as follows:

Authority: 42 U.S.C. 4001 *et seq.*; Reorganization Plan No. 3 of 1978, 3 CFR,

recordkeeping requirements, Sulfur oxides

40 CFR Part 72

Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Intergovernmental relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

40 CFR Part 75

Acid rain, Air pollution control, Carbon dioxide, Electric utilities, Incorporation by reference, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: March 15, 2005.

Stephen Johnson,

Acting Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, parts 60, 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 is amended by:

■ a. In the introductory text, the phrase "(MD–35)" is revised to read "(C267–01);"

■ b. In paragraph (a)(12), revising the term "77, 90, 91, 95, 98a" to read "77, 90, 91, 95, 98a, 99 (Reapproved 2004)^{e1};" revising the word "§§ 60.41(f)," to read "§§ 60.24(h)(8), 60.41(f);" and revising the words "and 60.251(b) and (c)." to read "60.251(b) and (c), and 60.4102."

■ c. In paragraph (a)(22), revising the term "87, 91, 97" to read "87, 91, 97, 03a" and revising the word §§ 60.41b and 60.41c" to read "§§ 60.41a of subpart Da of this part, 60.41b of subpart Db of this part, and 60.41c of subpart Dc of this part."

■ d. By adding paragraph (a)(76) to read as follows:

§ 60.17 Incorporations by Reference.

* * * * *

(a) * * *

(76) 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), IBR approved for appendix B to part 60, Performance Specification 12A, section 8.6.2.

* * * * *

■ 3. Section 60.21 is amended by:

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

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

§ 60.21 Definitions.

* * * * *

(a) *Designated pollutant* 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) *Emission standard* 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) *Allowance system* 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.

■ 4. Section 60.24 is amended by:

■ a. Revising paragraph (b)(1); and

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

§ 60.24 Emission standards and compliance schedules.

* * * * *

(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 November 17, 2006. 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

State	Annual EGU Hg budget (tons)	
	2010–2017	2018 and thereafter
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 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, 98a, or 99 (Reapproved 2004)[e1] (incorporated by reference, see § 60.17).

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.

Combustion turbine 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.

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

Electric generating unit or *EGU* 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 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 (1) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

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).

Gross thermal energy 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 generated by 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.

Operator 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.

Ounce means 2.84×10^7 micrograms.

Owner 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 seful

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); or

(2) For purposes of referring to a geographic area, one of the States in the United States, 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," "Dry flue gas desulfurization technology or dry FGD," "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" and "Wet flue gas desulfurization technology or wet FGD" 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, 98a, or 99 (Reapproved 2004)$^{\varepsilon 1}$ (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, 98a, or 99 (Reapproved 2004)$^{\varepsilon 1}$ (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.

Coal-fired electric utility steam generating unit 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.

* * * * *

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

* * * * *

Dry flue gas desulfurization technology or *dry 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 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 *IGCC* 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 D1835–87, 91, 97, or 03a (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. Redesignating § 60.49a as § 60.51a;
■ b. Redesignating § 60.48a as § 60.50a;
■ c. Redesignating § 60.47a as § 60.49a;
■ d. Redesignating § 60.46a as § 60.48a;
■ e. Redesignating § 60.45a as § 60.47a;
■ f. Adding new §§ 60.45a; and
■ g. Adding and reserving new § 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 (IGCC) 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 42×10^{-6} lb/MWh or 0.042 lb/GWh on an output basis. The SI equivalent is 0.0053 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 78×10^{-6} lb/MWh or 0.078 lb/GWh on an output basis. The SI equivalent is 0.0098 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 145×10^{-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 1.4×10^{-6} lb/MWh or 0.0014 lb/GWh on an output basis. The SI equivalent is 0.00018 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.

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

Where:

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

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

HH_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 IGCC 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 20×10^{-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).

§ 60.46a [Reserved]

■ 7. Newly redesignated § 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;
■ f. In paragraph (k)(2)(iii) by revising the existing references from "§ 60.47a(k)" to "§ 60.49a(k)";
■ g. In paragraph (k)(2)(iv) by revising the existing references from "§ 60.47a(l)" to "§ 60.49a(l)"; and
■ h. Adding new paragraph (l).

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.

* * * * *

(l) 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 redesignated § 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:

§ 60.49a Emission monitoring.

* * * * *

(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 redesignated § 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)";

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

■ 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.

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

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);

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

$V_{process}$ = 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:

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

Where:

E_h = Hg mass emissions for the hour, (lb)

K = Units conversion constant, 6.24×10^{-11} lb-scm/μg-scf

C_h = Hourly Hg concentration, wet basis, (μg/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:

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

Where:

E_h = Hg mass emissions for the hour, (lb)

K = Units conversion constant, 6.24×10^{-11} lb-scm/μg-scf

C_h = Hourly Hg concentration, dry basis, (μg/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^0 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^0 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 subpart Da 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 and reserving 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

Hg Budget Trading Program General Provisions

Sec.

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), 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), 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), 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.

Alternate 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 act on behalf of the Hg designated representative in matters pertaining to the Hg Budget Trading Program.

Automated data acquisition and handling system or *DAHS* 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.

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.

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, 98a, or 99 (Reapproved 2004)[e1] (incorporated by reference, see § 60.17).

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.

Combustion turbine 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.

Commence commercial operation 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.

Commence operation 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 (μg/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 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) shall not be a "Hg allowance."

Hg allowance deduction or *deduct Hg allowances* 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.

Hg allowances held or *hold Hg allowances* 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.

Hg Allowance Tracking System 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 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 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), 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 generated by 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.

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, 98a, or 99 (Reapproved 2004)$^{\varepsilon 1}$ (incorporated by reference, see § 60.17).

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 2.84×10^7 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.

Owner 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.

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); or

(2) For purposes of referring to geographic areas, one of the States in the United States, 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, 98a, or 99 (Reapproved 2004)$^{\varepsilon 1}$ (incorporated by reference, see § 60.17).

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.
H_2O—water.
Hg—mercury.
hr—hour.
kW—kilowatt electrical.
kWh—kilowatt hour.
lb—pound.
MMBtu—million Btu.
MWe—megawatt electrical.
MWh—megawatt hour.
NO_X—nitrogen oxides.
O_2—oxygen.
ppm—parts per million.
scfh—standard cubic feet per hour.
SO_2—sulfur dioxide.
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 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 statement 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.

§ 60.4106 Standard requirements.

(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.

(2) [Reserved]

(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.

§ 60.4107 Computation of time.

(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.

§ 60.4108 Appeal procedures.

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. 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" apply instead of 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."

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)(4)(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.

§ 60.4113 Certificate of Representation.

(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.

§ 60.4114 Objections concerning Hg Designated Representative.

(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]

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 divided 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 Hg 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 Hg 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.

§ 60.4161 EPA recordation.

(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).

§ 60.4171 Initial certification and recertification procedures.

(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, apply the word "recertification" instead of the words "certification" and "initial certification" and apply the word "recertified" instead of the word "certified," 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), 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 2.1.5, 2.1.3.1, and 2.1.3.2 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:

Appendix B to Part 60—Performance Specifications

* * * * *

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 $\mu g/m^3$ (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 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 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^0 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^0, 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, see § 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:

$$RD = 100 \times \left| (C_a - C_b) \right| / (C_a + C_b) \qquad \text{(Eq. 12A-1)}$$

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 $\mu g/m^3$. If the mean Hg concentration is less than or equal to 1.0 $\mu g/m^3$, 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 CEMS correlation or to assess CEMS RA.

8.6.7 Calculate the mean difference between the RM and CEMS values in the units of micrograms per cubic meter ($\mu g/m^3$), 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 CEMS responses), reference gas concentration certifications, and any other information necessary to confirm that the performance of the CEMS 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 CEMS must be compared in units of $\mu g/m^3$, 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 CEMS measure Hg on a different moisture basis, use Equation 12A–2 to make the appropriate corrections to the Hg concentrations.

$$\text{Concentration}_{(dry)} = \frac{\text{Concentration}_{(wet)}}{(1-B_{ws})} \qquad \text{(Eq. 12A-2)}$$

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:

$$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i \qquad \text{(Eq. 12A-3)}$$

Where:

n = Number of data points.

12.3 Standard Deviation. Calculate the standard deviation, S_d, as follows:

$$S_d = \left[\frac{\sum_{i=1}^{n} d_i^2 - \frac{\left[\sum_{i=1}^{n} d_i\right]^2}{n}}{n-1}\right]^{\frac{1}{2}} \qquad \text{(Eq. 12A-4)}$$

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:

$$CC = t_{0.975}\frac{S_d}{\sqrt{n}} \qquad \text{(Eq. 12A-5)}$$

12.5 RA. Calculate the RA of a set of data as follows:

$$RA = \frac{\left[\left|\bar{d}\right| + \left|CC\right|\right]}{\overline{RM}} \times 100 \qquad \text{(Eq. 12A-6)}$$

Where:

$\left|\bar{d}\right|$ = Absolute value of the mean differences (from Equation 12A-3).

$\left|CC\right|$ = 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 CEMS 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 CEMS must be no greater than 20 percent of the mean value of the RM test data in terms of units of $\mu g/m^3$. Alternatively, if the mean RM is less than 5.0 $\mu g/m^3$, the results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 1.0 $\mu g/m^3$.

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."