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40 CFR Parts 60 and 63

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[OAR–2002–0056; FRL–7606–3]

RIN 2060–AJ65

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In this document, EPA is proposing to: set national emission standards for hazardous air pollutants (NESHAP) pursuant to section 112 of the Clean Air Act (CAA); alternatively, to revise the regulatory finding that it made on December 20, 2000 (65 FR 79825) pursuant to CAA section 112(n)(1)(A); and if the December 2000 finding is revised as proposed herein, to set standards of performance for mercury (Hg) for new and existing coal-fired electric utility steam generating units (Utility Units), as defined in CAA section 112(a)(8), and for nickel (Ni) for new and existing oil-fired Utility Units pursuant to CAA section 111. The decision concerning which authority to base regulation of Hg and Ni emissions on, CAA section 112 or section 111, will depend upon whether EPA takes final action to revise the December 2000 section 112(n)(1)(A) finding in the manner described herein. In either event, however, EPA intends to require reductions in the emissions of Hg and Ni from coal- and oil-fired Utility Units, respectively. This action is one part of a broader effort to issue a coordinated set of emissions limitations for the power sector.

In December 2000, EPA found pursuant to CAA section 112(n)(1)(A) that regulation of coal- and oil-fired Utility Units under CAA section 112 is appropriate and necessary. Today's proposed section 112 ''MACT'' rule would require coal- and oil-fired Utility Units to meet hazardous air pollutant (HAP) emissions standards reflecting the application of the maximum achievable control technology (MACT) determined pursuant to the procedures set forth in CAA section 112(d). The EPA also is co-proposing and soliciting comment on implementing a cap-and-trade program under section 112, similar to that being proposed under section 111 of the CAA.

Coal- and oil-fired Utility Units emit a wide variety of metal, organic, and inorganic HAP, depending on the type of fuel that is combusted. The proposed CAA section 112 MACT rule would limit emissions of Hg and Ni. Exposure to Hg and Ni above identified thresholds has been demonstrated to cause a variety of adverse health effects.

Today's proposed amendments to CAA section 111 rules would establish a mechanism by which Hg emissions from new and existing coal-fired Utility Units would be capped at specified, nation-wide levels. A first phase cap would become effective in 2010 and a second phase cap in 2018. Facilities would demonstrate compliance with the standard by holding one ''allowance'' for each ounce of Hg emitted in any given year. Allowances would be readily transferrable among all regulated facilities. We believe that such a ''cap and trade'' approach to limiting Hg emissions is the most cost effective way to achieve the reductions in Hg emissions from the power sector that are needed to protect human health and the environment.

The added benefit of this cap-and-trade approach is that it dovetails well with the sulfur dioxide (SO_2) and nitrogen oxides (NO_X) Interstate Air Quality Rule (IAQR) published elsewhere in today's **Federal Register**. That proposed rule would establish a broadly-applicable cap and trade program that would significantly limit SO_2 and NO_X emissions from the power sector. The advantage of regulating Hg at the same time and using the same regulatory mechanism as for SO_2 and NO_X is that significant Hg emissions reductions can and will be achieved by the air pollution controls designed and installed to reduce SO_2 and NO_X. In other words, significant Hg emissions reductions can be obtained as a ''co-benefit'' of controlling emissions of SO_2 and NO_X. Thus, the coordinated regulation of Hg, SO_2, and NO_X allows Hg reductions to be achieved in a cost effective manner. This is consistent with Congress's intent expressed in CAA section 112(n), that EPA would regulate HAP emissions from Utility Units only after taking into account compliance with other CAA programs.

This action also proposes to add Performance Specification 12A, ''Specification and Test Methods for Total Vapor Phase Mercury Continuous Emission Monitoring Systems in Stationary Sources'' to 40 CFR part 60, appendix B, and to add one EPA method to 40 CFR part 63, appendix A: Method 324, ''Determination of Vapor Phase Flue Gas Mercury Emissions from Stationary Sources Using Dry Sorbent Trap Sampling.''

DATES: *Comments.* Submit comments on or before March 30, 2004.

Public Hearing. The EPA will be holding a public hearing on today's proposal during the public comment period. The details of the public hearing, including the time, date, and location, will be provided in a future **Federal Register** notice and announced on EPA's Web site for this rulemaking *http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg*. The public hearing will provide interested parties the opportunity to present data, views, or arguments concerning the proposed rules. The EPA may ask clarifying questions during the hearing, but will not respond to the presentations or comments at that time. Written comments and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at a public hearing.

ADDRESSES: *Comments.* Comments may be submitted by mail (in duplicate, if possible) to EPA Docket Center (Air Docket), U.S. EPA West (6102T), Room B–108, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Attention Docket ID No. OAR–2002–0056. By hand delivery/courier, comments may be submitted (in duplicate, if possible) to EPA Docket Center, Room B–108, U.S. EPA West, 1301 Constitution Ave., NW, Washington, DC 20460, Attention Docket ID No. OAR–2002–0056. Also, comments may be submitted electronically according to the detailed instructions as provided in the **SUPPLEMENTARY INFORMATION** section.

Public Hearing. The EPA will be holding a public hearing on today's proposal during the public comment period. The details of the public hearing, including the time, date, and location, will be provided in a future **Federal Register** notice and announced on EPA's Web site for this rulemaking *http://www.epa.gov/ttn/atw/combust/tuiltox/utoxpg*.

Docket. The official public docket is available for public viewing at the EPA Docket Center, EPA West, Room B–108, 1301 Constitution Ave., NW., Washington, DC 20460.

FOR FURTHER INFORMATION CONTACT: William Maxwell, Combustion Group (C439–01), Emission Standards Division, Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541–5430, fax number (919) 541–5450, electronic mail (e-mail) address, *maxwell.bill@epa.gov*.

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

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

[1] North American Industry Classification System.
[2] Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists examples of the types of entities EPA is now aware could potentially be regulated by this action. Other types of entities not listed could also be affected. To determine whether your facility, company, business, organization, etc., is regulated by this action, you should examine the applicability criteria in § 63.9981 of the proposed rule or §§ 60.45a and 60.46a of the proposed NSPS amendments. 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.

Docket. The EPA has established an official public docket for this action including both Docket ID No. OAR–2002–0056 and Docket ID No. A–92–55. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Not all items are listed under both docket numbers, so interested parties should inspect both docket numbers to ensure that they have received all materials relevant to the proposed rule. The official public docket is available for public viewing at the EPA Docket Center (Air Docket), EPA West, Room B–108, 1301 Constitution Ave., NW., Washington, DC. 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 Reading Room is (202) 566–1744, and 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 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 submit or view public comments, access the index listing of the contents of the official public docket, and access those documents in the public docket that are available electronically. Once in the system, select ''search,'' then key in the appropriate docket identification number.

Certain types of information will not be placed in EPA Dockets. Information claimed as confidential business information (CBI) and other information whose disclosure is restricted by statute, which is not included in the official public docket, will not be available for public viewing in EPA's electronic public docket. The EPA's policy is that copyrighted material will not be placed in EPA's electronic public docket but will be available only in printed paper form in the official public docket. To the extent feasible, publicly available docket materials will be made available in EPA's electronic public docket. When a document is selected from the index list in EPA Dockets, the system will identify whether the document is available for viewing in EPA's electronic public docket. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the EPA Docket Center.

For public commenters, it is important to note that EPA's policy is that public comments, whether submitted electronically or on paper, will be made available for public viewing in EPA's electronic public docket as EPA receives them and without change, unless the comment contains copyrighted material, CBI, or other information whose disclosure is restricted by statute. When EPA identifies a comment containing copyrighted material, EPA will provide a reference to that material in the version of the comment that is placed in EPA's electronic public docket. The entire printed comment, including the copyrighted material, will be available in the public docket.

Public comments submitted on computer disks that are mailed or delivered to the docket will be transferred to EPA's electronic public docket. Public comments that are mailed or delivered to the Docket will be scanned and placed in EPA's electronic public docket. Where practical, physical objects will be photographed, and the photograph will be placed in EPA's electronic public docket along with a brief description written by the docket staff.

For additional information about EPA's electronic public docket, visit EPA Dockets online or see 67 FR 38102, May 31, 2002.

You may submit comments electronically, by mail, or through hand delivery/courier. To ensure proper receipt by EPA, identify the appropriate docket identification number in the subject line on the first page of your comment. Please ensure that your comments are submitted within the specified comment period. Comments received after the close of the comment period will be marked ''late.'' The EPA is not required to consider these late comments. However, late comments may be considered if time permits.

Electronically. If you submit an electronic comment as prescribed below, EPA recommends that you include your name, mailing address, and an e-mail address or other contact information in the body of your comment. Also include this contact information on the outside of any disk or CD-ROM you submit, and in any cover letter accompanying the disk or CD-ROM. This ensures that you can be identified as the submitter of the comment and allows EPA to contact you in case EPA cannot read your comment due to technical difficulties or needs further information on the substance of your comment. The EPA's policy is that EPA will not edit your comment, and any identifying or contact information provided in the body of a comment will be included as part of the comment that is placed in the official public docket and made available in EPA's electronic public docket. 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.

Your use of EPA's electronic public docket to submit comments to EPA electronically is EPA's preferred method for receiving comments. Go directly to EPA Dockets at *http://www.epa.gov/edocket* and follow the online instructions for submitting comments. To access EPA's electronic public docket from the EPA Internet home page, select ''Information Sources,'' ''Dockets,'' and ''EPA Dockets.'' Once in the system, select ''search,'' and then key in Docket ID No. OAR–2002–0056. The system is an anonymous access system, which means EPA will not know your identity, e-mail address, or other contact information unless you provide it in the body of your comment.

Comments may be sent by e-mail to *a-and-r-docket@epa.gov,* Attention Docket ID No. OAR–2002–0056. In contrast to EPA's electronic public docket, EPA's e-mail system is not an anonymous access system. If you send an e-mail comment directly to the Docket without going through EPA's electronic public docket, EPA's e-mail system automatically captures your e-mail address. E-mail addresses that are automatically captured by EPA's e-mail system are included as part of the comment that is placed in the official public docket and made available in EPA's electronic public docket.

You may submit comments on a disk or CD–ROM that you mail to the mailing address identified below. These electronic submissions will be accepted in WordPerfect or ASCII file format. Avoid the use of special characters and any form of encryption.

By Mail. Send your comments (in duplicate if possible) to EPA Docket Center (Air Docket), U.S. EPA West (6102T), Room B–108, 1200 Pennsylvania Ave., NW., Washington, DC, 20460, Attention Docket ID No. OAR–2002–0056. The EPA requests a separate copy also be sent to the contact person listed above (*see* **FOR FURTHER INFORMATION CONTACT**).

By Hand Delivery or Courier. Deliver your comments (in duplicate, if possible) to EPA Docket Center, Room B–102, U.S. EPA West, 1301 Constitution Ave., NW., Washington, DC, 20460, Attention Docket ID No. OAR–2002–0056. Such deliveries are only accepted during the Docket's normal hours of operation as identified above.

By Facsimile. Fax your comments to (202) 566–1741, Attention Docket ID No. OAR–2002–0056.

CBI. Do not submit information that you consider to be CBI electronically through EPA's electronic public docket or by e-mail. Send or deliver information identified as CBI only to the following address: Mr. William Maxwell, c/o OAQPS Document Control Officer (Room C404–2), U.S. EPA, Research Triangle Park, 27711, Attention Docket ID No. OAR–2002–0056. You may claim information that you submit to EPA as CBI by marking any part or all of that information as CBI (if you submit CBI on disk or CD–ROM, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is CBI). Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

In addition to one complete version of the comment that includes any information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket and EPA's electronic public docket. If you submit the copy that does not contain CBI on disk or CD–ROM, mark the outside of the disk or CD–ROM clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and EPA's electronic public docket without prior notice. If you have any questions about CBI or the procedures for claiming CBI, please consult the person identified in the **FOR FURTHER INFORMATION CONTACT** section.

Public Hearing. Persons interested in presenting oral testimony should contact Ms. Kelly Hayes, Combustion Group (C439–01), Emission Standards Division, Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, North Carolina 27711, telephone (919) 541–5578, at least 2 days in advance of the public hearing. Persons interested in attending the public hearing must also call Ms. Kelly Hayes to verify the time, date, and location of the hearing.

The public hearing will provide interested parties the opportunity to present data, views, or arguments concerning the proposed rule. The EPA will ask clarifying questions during the oral presentation but will not respond to the presentations or comments. Written statements and supporting information will be considered with the same weight as any oral statement and supporting information presented at a public hearing.

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

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I. Background Information

A. What Is the Regulatory Development Background?

1. What Is the Statutory Background?

In the 1990 Amendments to the CAA, Congress substantially modified section 112 of the CAA, which is the provision of the CAA that expressly addresses HAP. Among other things, CAA section 112 sets forth a list of 188 HAP, to which EPA can add, and requires EPA to list categories and subcategories of ''major sources'' of listed pollutants. Congress defined ''major source'' as any stationary source [1] or group of stationary sources at a single location and under common control that emits or has the potential to emit 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP. (*See* CAA section 112(a)(1).)

Section 112 further requires EPA to list categories and subcategories of area sources [2] provided those sources meet one of the following statutory criteria: (1) EPA determines that the category or subcategory of area sources presents a threat of adverse effects to human health or the environment in a manner that warrants regulation under CAA section 112; or (2) the category or subcategory of area sources falls within the purview of CAA section 112(k)(3)(B) (the Urban Area Source Strategy). Once EPA has listed a source category, whether it be a category of major sources or area sources, section 112(d) calls for the promulgation of emission standards.

Congress, therefore, treated area sources differently from major sources in that categories of major sources are listed under CAA section 112 based solely on the number of tons of HAP emitted from sources in the category on an annual basis. By contrast, area source categories are not listed unless either the health and environmental effects warrant regulation under section 112, or reductions from the category are required to meet the requirements of the Urban Area Source Strategy.

Congress also treated Utility Units differently from major and area sources. (*See* CAA section 112(n)(1)(A).) Specifically, Congress directed EPA to conduct a study that analyzed what hazards to public health resulting from emissions of HAP from Utility Units, if any, would reasonably be anticipated to occur following imposition of the other requirements of the CAA. Congress further directed EPA to report to it the results of such study. Finally, Congress directed EPA to determine whether, based on the results of the study, regulation of Utility Units under CAA section 112 was appropriate and necessary. Congress did not define the terms ''appropriate'' and ''necessary,'' but required that regulation of Utility Units under section 112 occur only if EPA found such regulation to be both appropriate *and* necessary.

2. What Was the Scope of, and Basis for, EPA's December 2000 Finding?

Scope of finding. On December 20, 2000, pursuant to CAA section 112(n)(1)(A), EPA determined that it was both appropriate and necessary to regulate coal- and oil-fired Utility Units under section 112 of the CAA. (65 FR 79826) Solely because of this finding, EPA added these units to the list of source categories under section 112(c) of the CAA. (Id.) In December 2000, EPA also concluded that the impacts associated with HAP emissions from natural-gas fired Utility Units were negligible and that regulation of such units under CAA section 112 was not appropriate or necessary.

Basis for finding. Nature of record. The EPA premised its December 2000 ''appropriate and necessary'' finding primarily on the results of the February 1998 ''Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress'' (Utility RTC). The EPA prepared this study pursuant to the terms of CAA section 112(n)(1)(A) and provided it to Congress. The EPA also based its December 2000 finding on certain information that it obtained following completion of the Utility RTC, which served only to confirm the conclusions of the Utility RTC.

In the Utility RTC, EPA examined 67 of the 188 HAP listed in section 112(b) of the CAA. These 67 HAP represent the pollutants EPA believes could potentially be emitted from Utility Units. The EPA assessed these HAP in terms of potential health hazards and

[1] A ''stationary source'' of hazardous air pollutants is any building, structure, facility or installation that emits or may emit any air pollutant. CAA Section 111(a)(3).

[2] A stationary source that is not a major source is an ''area source.'' CAA section 112(a)(2).

summarized its conclusions with regard to the HAP in the Utility RTC.

The Utility RTC identifies Hg as the HAP emitted from Utility Units that is of greatest concern from a public health perspective. (Executive Summary Utility RTC (''ES''), at 27.) The health effects of Hg exposure are presented elsewhere in this preamble.

The Utility RTC also included information indicating that Ni was the pollutant of concern from oil-fired Utility Units due to its high level of emissions from those units and the potential health effects arising from exposure to it. The health effects of Ni exposure also are presented elsewhere in this preamble.

As for the other non-Hg and non-Ni metallic HAP examined, EPA made the following conclusions. With regard to arsenic, a metal, EPA concluded that there were several uncertainties associated with both the cancer risk estimates from arsenic and the health effects data for arsenic, and that further analyses were needed to characterize the risks posed by arsenic emissions from Utility Units (ES at 21). As to lead and cadmium, which are also metals, EPA found that the emission quantities and inhalation risks of these HAP were low and did not warrant further evaluation (ES at 24). As for the remaining, non-Hg, non-Ni metallic HAP, EPA found that such pollutants posed no hazards to public health.

The EPA also examined HCl and HF, which are inorganic or acid gas HAP, and found no exceedances of the health benchmark for either substance (ES at 24). As for dioxins, organic HAP, EPA concluded that the quantitative exposure and risk results for such HAP ''d(id) not conclusively demonstrate the existence of health risks of concern associated with exposures to utility emissions either on a national scale or from any actual individual utility.'' (Utility RTC at 11–5.) Finally, EPA concluded that emissions from Utility Units of the remaining HAP examined in the Study did not appear to be a concern for public health (65 FR 79827).

As part of the Utility RTC, EPA also examined several provisions of the CAA relating to electric utilities, including different sections of title I and title IV (Utility RTC, Ch.1). The EPA did not focus in the Utility RTC or the December 2000 finding, however, on whether section 111 of the CAA could be used specifically to regulate HAP from new and existing Utility Units, or the extent to which regulation under section 111 might address any HAP-related issues for Utility Units.

Following completion of the Utility RTC, EPA obtained additional information, which is summarized in EPA's December 20, 2000, notice. That information addressed Hg and methylmercury and confirmed the hazards to public health associated therewith.[4]

In addition, at the direction of Congress, EPA funded the National Academy of Sciences (NAS) to perform an independent evaluation of the available data related to the health impacts of methylmercury and provide recommendations for EPA's reference dose (RfD). An RfD is the amount of a chemical which, when ingested daily over a lifetime, is anticipated to be without adverse health effects to humans, including sensitive subpopulations. The NAS conducted an 18-month study of the available data on the health effects of methylmercury and provided EPA with a report of its findings in July 2000. Although the NAS recommended reliance on different studies for setting the methylmercury RfD, the value of EPA's RfD was found to be scientifically justifiable.

December 2000 finding. In December 2000, EPA found Hg to be the HAP emitted by Utility Units that was of greatest concern from a public health perspective because Hg is highly toxic, persistent, and bioaccumulates in food chains. The EPA also found that the data which it had gathered since the Utility RTC corroborated the previous nationwide Hg emissions estimate and confirmed that Utility Units are the largest anthropogenic source of Hg emissions in the United States. The EPA further found that there is a plausible link between methylmercury concentrations in fish and Hg emissions from coal-fired Utility Units (65 FR 79830).

Based on these findings, EPA stated that it was ''appropriate to regulate HAP emissions from coal- and oil-fired electric utility steam generating units under section 112 of the CAA because, as documented in the utility RTC * * *, electric utility steam generating units are the largest domestic source of Hg emissions and Hg in the environment presents significant hazards to public health and the environment.'' The EPA further noted that the National Academy of Science's study ''confirm(ed) that Hg in the environment presents significant hazards to public health.''

The EPA also found that it was appropriate to regulate HAP emissions from coal- and oil-fired Utility Units under CAA section 112 because EPA had identified several control options that should reduce these emissions. (*See* 65 FR 79830 (noting that ''There are a number of alternative control strategies that are effective in controlling *some of the HAP* emitted from electric utility steam generating units.'') (emphasis added).) Thus, EPA's appropriateness finding in December 2000 focused on the significant health hazards associated with Hg and the availability of control strategies for certain HAP. The determination also rested, in part, however, on the uncertainties regarding the public health effects associated with HAP from oil-fired units. (*See* 65 FR 79830.) Although EPA did not specify in the December 2000 notice which HAP emissions from oil-fired units posed hazards to public health that warrant regulation, the record demonstrates that Ni was the HAP emitted by oil-fired units that was of greatest concern from a public health perspective because of the significant quantities of Ni emitted from oil-fired units and the scope and number of adverse health effects associated with Ni exposure. However, only 11 of the 137 oil-fired Utility Units considered in this finding posed an inhalation risk to human health greater than one in a million (1×10^{-6}).

Finally, EPA stated that it was ''necessary'' to regulate HAP emissions from coal- and oil-fired Utility Units ''because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from such emissions.'' (*See* 65 FR 79830.)

The EPA had a desire to keep the regulatory process open and include all stakeholders involved. After discussion with the various stakeholder groups, it was decided that the most effective means of ensuring that inclusion was to form a Working Group under the existing Permits, New Source Review, and Toxics Subcommittee of the Clean Air Act Advisory Committee (CAAAC), chartered under the Federal Advisory Committee Act (FACA). The Working Group was designed and created to foster active participation from stakeholders, including environmental groups, the regulated industry, and State and local regulatory agencies. Over the period of August 2001 to March 2003, the Working Group held 14 meetings and discussed a number of issues related to the proposed CAA section 112 rule.

[4] Subsequent to issuance of the December 2000 Notice, EPA also conducted additional modeling for HCl, chlorine (Cl_2), and HF. Such modeling predicted concentrations of these HAP to be well below the relevant respiratory benchmark concentrations for the model plants examined. Hazard indices did not exceed 0.2 for any of these HAP. This modeling, therefore, confirmed the conclusion EPA reached in the Utility RTC, which is that inorganic or acid gas HAP from Utility Units, even in the absence of additional control measures, do not pose any hazards to the public health.

To enhance the public's ability to participate, EPA maintained an Internet website to disseminate information on the Working Group and the regulatory process. The recommendations of the Working Group and other interested parties have been considered by EPA in developing the proposed rule for coal- and oil-fired Utility Units. On several occasions, EPA met with individual stakeholder groups to discuss the status of the proposed rulemaking and to hear their concerns and comments regarding the proposed CAA section 112 rule.

B. What Is the Relationship Between the Proposed Rule and Other Combustion Rules?

The EPA has previously developed two other combustion-related MACT standards in addition to today's proposed rule for coal- and oil-fired Utility Units. The EPA proposed standards for industrial, commercial, and institutional boilers and process heaters (IB) on January 13, 2003 (68 FR 1660) and promulgated standards for stationary combustion turbines (CT) in 2004. These regulations have been issued pursuant to CAA section 112, but not under CAA section 112(n)(1)(A), as is today's proposal, because section 112(n)(1)(A) is uniquely applicable to Utility Units as defined by the CAA.

All three of the rules pertain to HAP emission sources that combust fossil fuels for electrical power, process operations, or heating. The differences among these rules are due to the size of the unit (megawatts electric (MWe) or British thermal unit per hour (Btu/hr)) they regulate, the boiler/furnace technology they employ, or the portion of their electrical output (if any) for sale to any utility power distribution systems.

Section 112(a)(8) of the CAA defines an ''electric utility steam generating unit'' as ''any fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale.'' A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered a Utility Unit. All of the MWe ratings quoted in the proposed rule are considered to be the original nameplate rated capacity of the unit. Cogeneration is defined as the simultaneous production of power (electricity) and another form of useful thermal energy (usually steam or hot water) from a single fuel-consuming process. Today's proposed section 112 MACT rule would not regulate a unit that meets the definition of a Utility Unit but combusts natural gas greater than 98 percent of the time.

The CT rule regulates HAP emissions from all simple-cycle and combined-cycle turbines producing electricity or steam for any purpose. Because of their combustion technology, simple-cycle and combined-cycle turbines (with the exception of integrated gasification combined cycle (IGCC) units that burn gasified coal gas) are not considered Utility Units for purposes of today's proposed rule.

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

Because of the similarities in the design and operational characteristics of the units that would be regulated by the different combustion rules, there are situations where coal- or oil-fired units potentially could be subject to multiple MACT rules. An example of this situation would be cogeneration units that are covered under the proposed IB rule, potentially meeting the definition of a Utility Unit, and vice versa. This might occur where a decision is made to increase/decrease the proportion of production output being supplied to the electric utility grid, thus causing the unit to exceed the IB/electric utility cogeneration criteria (*i.e.* greater than one-third of its potential output capacity and greater than 25 MWe).

The EPA solicits comment on the extent to which this situation might occur. Given the differences between rules, how should EPA address reclassification of the sources between the two rules, particularly with regard to initial and ongoing compliance requirements and schedules? (As noted above, EPA is proposing to consider as a Utility Unit any cogeneration unit that meets the definition noted earlier at any time during a year.)

Another situation could occur where one or more coal- or oil-fired Utility Unit(s) share an air pollution control device (APCD) and/or an exhaust stack with one or more similarly-fueled IB units. To demonstrate compliance with two different rules, the emissions have to either be apportioned to the appropriate source or the more stringent emission limit must be met. Data needed to apportion emissions are not currently required by the proposed rule or the proposed IB rule.

The EPA solicits comment on the extent to which this situation might occur. Given potential differences between rules, how should EPA address apportionment of the emissions to the individual sources with regard to initial and ongoing compliance requirements? The EPA specifically requests comment on the appropriateness of a mass balance-type methodology to determine pollutant apportionment between sources both pre-APCD and post-APCD.

C. What Are the Health Effects of HAP Emitted From Coal- and Oil-Fired Utility Units?

Data collected during development of the proposed section 112 rule show that coal- and oil-fired Utility Units emit a wide variety of metal, organic, and inorganic HAP, depending on the type of fuel that is combusted. Today's proposed rules, both under CAA section 111 and 112, would protect air quality and promote the public health by reducing emissions of Hg and Ni from coal- and oil-fired Utility Units. Exposure to Hg and Ni at sufficiently high levels is associated with a variety of adverse health effects. The EPA cannot currently quantify whether, and the extent to which, the adverse health effects occur in the populations surrounding these facilities, and the contribution, if any, of the facilities to those problems. However, to the extent the adverse effects do occur, either of today's proposed actions would reduce emissions and subsequent exposures. Following is a summary of the health effects for the Hg and Ni emissions that would be reduced by either of the proposed rules.

Mercury. Mercury is a persistent, bioaccumulative toxic metal that exists in three forms: elemental Hg (Hg^0), inorganic Hg (Hg^{++}) compounds (primarily mercuric chloride), and organic Hg compounds (primarily methylmercury). Each form exhibits different health effects. Various major sources may release elemental or inorganic Hg; environmental methylmercury, the form of concern for this rulemaking, is typically formed by biological processes after Hg has precipitated from the air and deposited into water bodies.

Mercury is toxic to humans from both the inhalation and oral exposure routes. In the proposed rulemaking, we focus

on oral exposure of methylmercury as it is the route of primary interest for human exposures. Methylmercury is a well-established human neurotoxin although, as with many chemicals, the scientific community is divided on the specific dose and frequency of exposure required to elicit adverse effects. According to the NAS, chronic low-dose prenatal methylmercury exposure has been associated with poor performance on neurobehavioral tests in children, including those tests that measure attention, visual-spacial ability, verbal memory, language ability, fine motor skills, and intelligence. Furthermore, it has been hypothesized that there is an association between methylmercury exposure and an increased risk of coronary disease in adults; however, this hypothesis warrants further study as the few studies currently available present conflicting results. (NEJOM; 2002; Yoshizawa, 2002; Guallar, 2002; Salonen, 1999; Salonen, 1995; Bolger, 2003).

Fish consumption dominates the pathway for human and wildlife exposure to methylmercury. There is a great deal of variability among individuals in fish consumption rates. Critical elements in estimating methylmercury exposure and risk from fish consumption include the species of fish consumed, the concentrations of methylmercury in the fish, the quantity of fish consumed, and how frequently the fish is consumed. The typical U.S. consumer eating a wide variety of fish from restaurants and grocery stores is not in danger of consuming harmful levels of methylmercury from fish and is not advised to limit fish consumption. Those who regularly and frequently consume large amounts of fish, either marine or freshwater, are more exposed. Because the developing fetus may be the most sensitive to the effects from methylmercury, women of child-bearing age are regarded as the population of greatest interest. The EPA, Food and Drug Administration, and many States have issued fish consumption advisories to inform this population of protective consumption levels.

The EPA's 1997 Mercury Study RTC supports a plausible link between anthropogenic releases of Hg from industrial and combustion sources in the U.S. and methylmercury in fish. However, these fish methylmercury concentrations also result from existing background concentrations of Hg (which may consist of Hg from natural sources, as well as Hg which has been re-emitted from the oceans or soils) and deposition from the global reservoir (which includes Hg emitted by other countries). Given the current scientific understanding of the environmental fate and transport of this element, it is not possible to quantify how much of the methylmercury in fish consumed by the U.S. population is contributed by U.S. emissions relative to other sources of Hg (such as natural sources and re-emissions from the global pool). As a result, the relationship between Hg emission reductions from Utility Units and methylmercury concentrations in fish cannot be calculated in a quantitative manner with confidence. In addition, there is uncertainty regarding over what time period these changes would occur. This is an area of ongoing study.

Given the present understanding of the Hg cycle, the flux of Hg from the atmosphere to land or water at one location is comprised of contributions from: the natural global cycle; the cycle perturbed by human activities; regional sources; and local sources. Recent advances allow for a general understanding of the global Hg cycle and the impact of the anthropogenic sources. It is more difficult to make accurate generalizations of the fluxes on a regional or local scale due to the site-specific nature of emission and deposition processes. Similarly, it is difficult to quantify how the water deposition of Hg leads to an increase in fish tissue levels. This will vary based on the specific characteristics of the individual lake, stream, or ocean.

As part of routine U.S. population surveillance, the U.S. Centers for Disease Control (CDC) assessed Hg concentrations in blood of over 1,500 women of child-bearing age. A recent analysis of these data reported that about 8 percent of these women of child-bearing age have levels of Hg in their blood that are at or above the U.S. EPA's RfD. The CDC also surveyed the same group of women about their eating habits. The surveyed women reported eating shrimp and tuna more frequently than other fish and shellfish options. Hg concentrations in seafood may be largely responsible for elevated levels of Hg in U.S. women of child-bearing age. We have little information about how Hg emissions from U.S. power plants may affect Hg concentrations in shrimp, tuna, and other marine fish. We seek comment on this issue and in particular, any data or other information that would allow us to better estimate the extent to which today's proposal would reduce blood Hg concentrations in U.S. women.

Recent estimates (which are highly uncertain) of annual total global Hg emissions from all sources (natural and anthropogenic) are about 5,000 to 5,500 tons per year (tpy). Of this total, about 1,000 tpy are estimated to be natural emissions and about 2,000 tpy are estimated to be contributions through the natural global cycle of re-emissions of Hg associated with past anthropogenic activity. Current anthropogenic emissions account for the remaining 2,000 tpy. Point sources such as fuel combustion; waste incineration; industrial processes; and metal ore roasting, refining, and processing are the largest point source categories on a world-wide basis. Given the global estimates noted above, U.S. anthropogenic Hg emissions are estimated to account for roughly 3 percent of the global total, and U.S. utilities are estimated to account for about 1 percent of total global emissions. (Utility RTC at 7–1 to 7–2.)

Nickel. Nickel is a natural element of the earth's crust; therefore, small amounts are found in food, water, soil and air. Food is the major source of Ni exposure. Ni is an essential element in some animal species. Individuals may also be exposed to Ni if they are employed in occupations involved in Ni production, processing, and use, or through contact with every day items such as Ni-containing jewelry and stainless steel cooking and eating utensils, and by smoking tobacco. The route of human exposure to Ni that we are concerned with in this rulemaking is Ni that is found in ambient air at very low levels as a result of releases from oil-fired Utility Units. The differing forms of Ni have varying levels of toxicity. There is great uncertainty about the different species of Ni emitted by Utility Units.

Respiratory effects, including a type of asthma specific to Ni, decreased lung function and bronchitis have been reported in humans who have been occupationally exposed to high-levels of Ni in air. Animal studies have reported effects on the lungs and immune system from inhalation exposure to soluble and insoluble Ni compounds (nickel oxide, subsulfide, sulfate heptahydrate). Soluble Ni compounds are more toxic to the respiratory tract than less soluble compounds. The EPA has not established a reference concentration (RfC)for Ni. No information is available regarding the reproductive or developmental effects of Ni in humans, but animal studies have reported such effects, although a consistent dose-response relationship has not been seen. Human and animal studies have reported an increased risk of lung and nasal cancers from exposure to Ni refinery dusts and Ni subsulfide. The EPA has classified Ni carbonyl as a Group B2, probable human carcinogen based on lung tumors in animals. (*see*

http://www.epa.gov/ttn/atw/hlthef/nickel.html).

We ask for comment on all aspects of our proposed revised determination that it is necessary and appropriate to regulate Ni emissions from oil-fired Utility Units under section 112. In particular, we ask for comments and additional information related to the speciation of Ni compounds directly emitted by oil-fired Utility Units and those that may be formed through atmospheric transformation, as well as information on potential health effects. We also ask commenters—especially current owners and operators of potentially affected oil-fired units—to provide information on the current operating status and anticipated mode of operation in the future of potentially affected oil-fired Utility Units, including current control technology. To the extent possible, we would like to have up-to-date information on fuel use, emissions, stack parameters and other location-specific data that would be relevant to the assessment of emissions, dispersion, and ambient air quality. We also ask for comment on our finding in the Utility RTC that only 11 of 137 oil-fired Utility Units considered in the Utility RTC posed an inhalation risk to human health greater than one in a million (1×10^{-6}) and whether data exists as to whether emissions from these plants no longer pose such risk.

II. Proposed National Emission Standards for Hazardous Air Pollutants for Mercury and Nickel From Stationary Sources: Electric Utility Steam Generating Units

A. What Is the Statutory Authority for the Proposed Section 112 Rule?

Section 112 of the CAA requires that EPA promulgate regulations requiring the control of HAP emissions from listed categories of sources. The control of HAP is typically achieved through promulgation of emission standards under sections 112(d) and (f) of the CAA and, in appropriate circumstances, work practice standards under section 112(h) of the CAA.

Section 112(n)(1)(A), which provides the authority for today's proposed section 112 rule, states as follows:

> The Administrator shall perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of pollutants listed under subsection (b) after imposition of the requirements of this Act. The Administrator shall report the results of this study to the Congress within 3 years after the date of the enactment of the Clean Air Act Amendments of 1990. The Administrator shall develop and describe in the Administrator's report to Congress alternative control strategies for emissions which may warrant regulation under this section. The Administrator shall regulate electric utility steam generating units under this section, if the Administrator finds such regulation is appropriate and necessary after considering the results of the study required by this subparagraph.

By its express terms, section 112(n)(1)(a) applies only to Utility Units. It establishes certain predicates and requirements that are uniquely applicable to the regulation of Utility Units, and that have not been the subject of previous EPA regulatory decisions under section 112. In the circumstances presented here, and as discussed below, EPA interprets section 112(n)(1)(A) only to authorize the Agency to promulgate section 112 standards for Utility Units with respect to HAP emissions from such units that are reasonably anticipated to result in a hazard to public health after imposition of the other requirements of the CAA. To the extent section 112 can be interpreted as authorizing but not requiring EPA to go beyond that, and to promulgate section 112 standards for HAP emissions that are not reasonably anticipated to result in a hazard to public health, EPA has decided not to do so.

Section 112(n)(1)(a) contains four basic instructions to EPA. First, EPA must prepare a study on ''the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of * * * [HAP] * * * after imposition of the requirements of this Act,'' and submit the results in a report to Congress. Second, EPA must develop alternative control strategies for HAP emissions from Utility Units and describe them in the report. Third, and ''after considering the results of the study required by'' section 112(n)(1)(A), the EPA may determine whether regulation of Utility Units under section 112 is ''appropriate and necessary.'' Finally, if EPA determines that regulation under section 112 is appropriate and necessary, EPA must promulgate such regulations.

We carried out our obligations with respect to the first of these instructions when we completed and submitted to Congress in February 1998 the Utility RTC. The Utility RTC did not expressly state conclusions about any HAP, other than Hg, that was known to be emitted from coal-fired Utility Units. The RTC also included information indicating that Ni emissions from oil-fired Utility Units are of concern. Additionally, the ICR conducted in 1999 served to collect data and inform the EPA further only with respect to Hg emissions from coal-fired units, the pollutant of greatest concern in the health-based Utility RTC.

The Utility RTC also carried out a portion of the second instruction—the development of alternative control strategies. Later in this notice, we will discuss additional alternative control strategies.

We carried out the third step in the section 112(n)(1)(A) process when, on December 20, 2000, EPA published a ''Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units.'' (65 FR 79825) We determined at that time that it was appropriate to regulate HAP emissions from coal- and oil-fired Utility Units because: (1) Such units ''are the largest domestic source of [Hg] emissions, and [Hg] in the environment presents significant hazards to public health and the environment;'' and (2) we had ''identified a number of control options which EPA anticipates will effectively reduce HAP emissions from such units.'' *Id.* at 79830. The EPA also found that ''regulation of HAP emissions from natural gas-fired electric utility steam generating units is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible based on the results of the study documented in the [U]tility RTC.'' *Id.* at 79831. We have found no reason to reconsider or revise that finding, and therefore today's proposed section 112 rule does not address gas-fired Utility Units.[5]

Thus, EPA's appropriateness finding in December 2000 focused on the significant health hazards associated with Hg and the availability of control strategies for certain HAP from coal-fired Utility Units. The finding also rested, in part, however, on the uncertainties regarding the public health effects associated with HAP from oil-fired units. Id. Although EPA did not specify in the December 2000 finding which HAP emissions from oil-fired units posed hazards to public health, the record demonstrates that Ni was the HAP of greatest concern from a public health perspective because of the quantities of Ni emitted from oil-fired Utility Units and the scope and number of adverse health effects associated with Ni exposure.

Our December 2000 finding stated that it was necessary to regulate HAP

[5] As EPA stated in the December 2000 finding, it does not believe that the definition of electric utility steam generating unit found in section 112(a)(8) of the Act encompasses stationary combustion turbines. 65 FR 79831. Therefore, today's proposed section 112 regulation does not address stationary combustion turbines. As further discussed elsewhere in this preamble, stationary combustion turbines are covered under the combustion turbine MACT standard.

emissions from coal- and oil-fired Utility Units under section 112 ''because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from such emissions identified in the [U]tility RTC and confirmed by the NAS study, and which section 112 is intended to address.'' *Id.* at 79830.

While the December 2000 finding recounts at length the Agency's analysis and conclusions concerning the health risks from Hg exposure, it does not expressly state findings about health risks that are presented by other HAP emissions from Utility Units.

With today's notice, EPA is proposing to carry out the fourth of the four instructions in section 112(n)(1)(A)—that is, EPA is proposing to regulate Utility Units under section 112. In doing so, a threshold question is presented as to whether EPA must regulate the two HAP that were the primary focus of the step 2 finding, or whether it must regulate emissions of all HAP listed in section 112(b). Section 112(n)(1)(A) provides no express direction to EPA as to the HAP that should be addressed if we determine that regulation of Utility Units under section 112 is appropriate and necessary.

The EPA interprets section 112(n)(1)(A) as only authorizing regulation of Utility Units under section 112 with respect to HAP emissions from such units that EPA has determined are ''appropriate and necessary'' to regulate under section 112 because they are reasonably anticipated to result in a hazard to public health even after imposition of the other requirements of the CAA. Because EPA's December 2000 determination only made such a finding as to, at most, Hg emissions from coal-fired units and Ni emissions from oil-fired units, today's section 112 proposal only addresses those HAP emissions from the respective units.

As explained above, section 112(n)(1)(A) sets forth a regulatory scheme that is predicated on the completion of a study of hazards to public health. The EPA is to develop and describe in the report ''alternative control strategies for emissions which may warrant regulation under this section,'' and then may determine regulation of the source category ''is appropriate and necessary after considering the results of the study.'' Fairly read, this section requires EPA to narrowly focus any regulation it may promulgate pursuant to this authority. Indeed, an interpretation of section 112(n)(1)(A) that it automatically requires EPA to regulate HAP emissions from Utility Units for which no health hazard had been found would effectively read out of the statute much of the language set forth in this section and render superfluous much of the section 112(n)(1)(A) processes and requirements.

More specifically, the study that EPA is required to perform is to address the ''hazards to public health reasonably anticipated to occur as a result of'' HAP emissions by Utility Units. The EPA is authorized to regulate under section 112 only if the Agency ''finds such regulation is appropriate and necessary *after considering the results of the study required by this subparagraph*.'' (Emphasis added.) Because the decision to regulate is expressly linked to the results of the study, it is reasonable to interpret section 112(n)(1)(A) as authorizing EPA to promulgate section 112 emissions regulations for Utility Units only with respect to the HAP that the EPA has determined are appropriate and necessary to regulate under this section. Furthermore, EPA is directed to develop and describe ''alternative control strategies for emissions *which may warrant regulation under this section*.'' (Emphasis added.) The emphasized phrase signals that an ''appropriate and necessary'' finding under section 112(n)(1)(A) does not require EPA to regulate emissions of all HAP from Utility Units once an ''appropriate and necessary'' finding as to at least one HAP has been made. In fact, that phrase has no meaning at all if EPA automatically is required to regulate all HAP from electric utility steam generating units once EPA makes an ''appropriate and necessary'' finding. The EPA believes the better interpretation of this language is that an appropriate and necessary finding can be made as to emissions of some HAP but not others, and trigger a requirement to promulgate section 112 regulations only as to the specific HAP for which the Agency has made the ''appropriate and necessary'' finding.

It might be argued that, even though our section 112(n)(1)(A) finding was based on concern about hazards to human health only from particular HAP, that the ''under this section'' phrase means that once EPA makes an ''appropriate and necessary'' finding with respect to the emissions of any one HAP, EPA must regulate all HAP listed in CAA section 112(b). That, in fact, is what EPA is required to do with respect to source categories other than Utility Units (*i.e.*, source categories to which section 112(n)(1)(A) does not apply). *See National Lime Association* v. *EPA,* 223 F.3d 625 (D.C. Cir. 2000).

The EPA rejects such an interpretation of section 112(n)(1)(A). As explained above, EPA believes that interpreting section 112(n)(1)(A) in this manner would ignore much of the language set forth in that section, and would render superfluous the section's processes and requirements. By contrast, EPA's interpretation gives meaning to all of the words of section 112(n)(1)(A) and is consistent with requiring regulation under section 112 only of those HAP emissions from Utility Units that are identified as appropriate and necessary to regulate under section 112 because they are reasonably anticipated to result in a hazard to public health after imposition of the other requirements of the CAA.

Our interpretation of section 112(n)(1)(A) is supported by the legislative history of this section. The House version of what became section 112(n)(1)(A) was adopted in lieu of the Senate provision. Senate Bill S. 1630, which contained the version that was not adopted, would have required regulation of HAP from Utility Units under section 112(d), notwithstanding the results of certain mandated studies. The House language, by contrast, did not presume that regulation was needed and certainly did not require that EPA regulate all HAP emissions from Utility Units if it regulated any. ''[I]f the Administrator regulates any of these units, he may regulate only those units that he determines—after taking into account compliance with all provisions of the Act and any other Federal, State or local regulation and voluntary emission reductions—have been demonstrated to cause a significant threat of adverse effects on the public health.'' 136 Cong. Rec. E3670, E3671 (Nov. 2, 1990) (statement of Cong. Oxley).

Finally, even if it is possible to construe section 112(n)(1)(A) as allowing EPA to regulate Utility Unit emissions of all HAP listed in section 112(b) once the EPA has made an ''appropriate and necessary'' finding under section 112(n)(1)(A) with respect to any one or more HAP, we still believe that the better interpretation and application of that section is for EPA only to regulate HAP emissions that EPA has determined are ''appropriate and necessary'' to regulate under section 112 after imposition of the other requirements of the CAA. The EPA believes it would not be consistent with the policy Congress established when it enacted a separate section 112(n)(1)(A) for Utility Units, and required EPA to conduct a public health study and make a determination of appropriateness and necessity, for EPA to decide that utilities simply should be subject to the same types of regulation and in the

same form as all other sources, despite the lack of any health-based finding that regulation of all HAP is appropriate or necessary. Furthermore, and as discussed elsewhere in this notice, such an interpretation would impose regulatory mandates with no discernable benefit to public health. The EPA is not inclined to impose costly regulatory mandates with no discernable public health benefit in the absence of clear direction by Congress that EPA must do so.

In developing today's proposed section 112 MACT rule, EPA has decided, as one regulatory option, to employ the section 112(d) process and propose a MACT standard. This is the result of EPA's having accompanied its December 2000 finding with a decision to list coal-fired and oil-fired Utility Units under section 112(c) of the CAA (65 FR 79825, 79830, December 20, 2000).

A standard developed pursuant to section 112(d) must reflect the maximum degree of reductions in emissions of HAP that is achievable taking into consideration the cost of achieving emissions reductions, any non-air-quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as MACT. The MACT standards can be based on the emissions reductions achievable through application of measures, processes, methods, systems, or techniques including, but not limited to: (1) Reducing the volume of, or eliminating emissions of, such pollutants through process changes, substitutions of materials, or other modifications; (2) enclosing systems or processes to eliminate emissions; (3) collecting, capturing, or treating such pollutants when released from a process, stack, storage or fugitive emission point; (4) implementing design, equipment, work practices, or operational standards as provided in subsection 112(h) of the Act; or (5) a combination of the above.

For new sources, MACT standards cannot be less stringent than the emission control achieved in practice by the best-controlled similar source. The MACT standards for existing sources can be less stringent than standards for new sources, but they cannot be less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources (for which the Administrator has emissions information) for categories and subcategories with 30 or more sources, or the best-performing 5 sources for categories or subcategories with fewer than 30 sources.

Even though EPA has developed today's proposed section 112 MACT rule pursuant to section 112(d)'s procedures and standards, section 112(n)(1)(A) expressly calls for EPA to develop ''alternative control strategies'' for the regulation of HAP emissions that ''may warrant regulation'' under section 112. In addition, section 112(n)(1)(A) specifies that any regulation should be ''appropriate and necessary'' in light of ''hazards to public health reasonably expected to occur''—a departure from the traditional section 112(d) approach applicable to other types of sources. As set forth in the second part of today's notice, EPA is proposing to revise the December 2000 regulatory finding, to remove coal- and oil-fired Utility Units from the section 112(c) list, and instead to regulate Hg emissions from coal-fired Utility Units and Ni emissions from oil-fired units pursuant to existing authority in section 111 of the Act.

But as an alternative to revising the December 2000 finding and regulating under section 111, EPA believes it also has authority to leave the December 2000 ''appropriate and necessary'' finding in place, and to proceed to regulate under section 112(n) of the Act. In that event, EPA could promulgate, under section 112(n)(1)(A), a cap-and-trade program for Hg somewhat like the one that EPA is today proposing pursuant to CAA section 111. Therefore, and as another alternative, EPA also is proposing in today's notice to remove coal-fired Utility Units from the section 112(c) list, and to promulgate pursuant to section 112(n)(1)(A) a cap-and-trade program for Hg from coal-fired Utility Units.

In implementing this program under section 112, EPA would adopt a cap that reflects the projected Hg emissions that would occur under the section 112 MACT approach, which EPA currently projects to be 34 tons per year under the MACT proposal set forth in today's notice. The EPA would apportion this cap level of annual emissions across coal-fired units using the proposed MACT emission limits presented in Tables 1 and 2 and the proportionate share of their baseline heat input to total heat input of all affected units. Alternatively, EPA would apportion this cap level of annual emissions across all coal-fired Utility Units in accordance with the emission guidelines associated with the section 111 cap-and-trade proposal, contained in today's proposal. The EPA would implement a MACT cap-and-trade rule using a model trading rule similar to the model rule that we would use for our section 111 trading proposal. The EPA explains below its interpretation of CAA section 112 and why these trading approaches are permissible under section 112, and solicits comment on these approaches.

Section 112(n), which is quoted in part above, provides EPA's authority to regulate HAP emissions from Utility Units. By its express terms, section 112(n)(1)(A) applies only to such units and establishes certain predicates and requirements that are uniquely applicable to the regulation of this source category. In the typical cases of regulating HAP from other source categories, EPA's regulatory authority is derived from section 112(d), which prescribes a relatively rigid, plant-by-plant, MACT approach. By contrast, section 112(n) can be interpreted to authorize a more flexible, risk-based approach; there is nothing in section 112(n)(1)(A) that requires an ''appropriate and necessary'' finding to result in a section 112(c) listing or regulation under section 112(d).

While section 112(d) mandates regulation of all HAP emissions based on the emissions limitations achieved by similar sources, section 112(n) calls for regulation of Utility Unit HAP emissions as EPA determines is ''appropriate and necessary after considering the results of the study'' of public health hazards reasonably anticipated to occur from those Utility Unit HAP emissions. Congress provided EPA with distinct regulatory authority to address HAP emissions from Utility Units ''because of the logic of basing any decision to regulate on the results of scientific study and because of the emission reductions that will be achieved and the extremely high costs that electric generators will face under other provisions of the new Clean Air Act Amendments.'' 136 Cong. Rec. E3670, E3671 (Nov. 2, 1990) (statement of Cong. Oxley).

Congress's intent to authorize EPA to regulate Utility Unit HAP emissions in ways other than with the prescriptive requirements of section 112(d) is indicated by the section 112(n) requirement that EPA develop alternative control strategies for HAP emissions from these units. These alternative control strategies must address the hazards to public health that EPA reasonably anticipates will occur as a result of Utility Unit HAP emissions. Congress authorized EPA to consider a wider range of control alternatives for the utility sector than the source-by-source approach EPA has prescribed in standards for other source categories under the traditional section 112(d) MACT approach. Because Congress directed EPA to develop control strategies that would be alternatives to the usual section 112(d) MACT

standard, it is reasonable to conclude that Congress authorized EPA to implement such alternatives.

As a result, EPA believes that section 112(n) confers on the Agency the authority to develop a system-wide or pooled performance standard for HAP emissions from Utility Units. Notably, in the December 2000 section 112(n)(1)(A) finding, we identified the ''considerable interest in an approach to Hg regulation for power plants that would incorporate economic incentives such as emissions trading.'' 65 FR at 79830. We also offered the conclusion that ''[r]ecent data * * * indicate the possibility for multipollutant control with other pollutants (*e.g.*, NO_X, SO_2, and PM), greatly reducing mercury control costs.''

In addition, section 112(n)(1)(A) specifies that any regulation of HAP emissions from Utility Units should be ''appropriate and necessary'' in light of ''hazards to public health reasonably anticipated to occur''—a departure from the traditional 112(d) approach applicable to other types of sources. Read as a whole, section 112(n)(1)(A) could be read to grant authority to develop and propose different control mechanisms than might be required under the section 112(d) approach. Under this reading, EPA could adopt any control strategy that is ''appropriate and necessary'' in light of ''hazards to public health reasonably anticipated to occur.''

As discussed at length elsewhere in today's notice, a trading approach for Utility Unit emissions of Hg has many advantages over a prescriptive, technology-based approach such as a MACT. *See* discussion, *infra,* section IV(D). We also reiterate that a cap and trade approach to controlling Hg emissions dovetails well with our proposal concerning an IAQR. *See* discussion, *infra,* section IV. Accordingly, a trading approach for Hg is consistent with Congress's direction in section 112(n)(1)(A) that any EPA regulation of HAP emissions from Utility Units must take into account compliance by those units with regulations and emissions reductions under other provisions of the CAA.

In past MACT rulemakings and with respect to source categories other than Utility Units, EPA has not resolved whether a system-wide or pooled performance standard is permitted under section 112(d). However, EPA has under the authority of section 112(d) established affected source-wide emissions averaging provisions that do not necessarily require each regulated source to apply controls. The EPA requests comment on whether we can expand upon this idea and establish a program similar to the program we believe could be promulgated pursuant to section 112(n), including system averaging, based on section 112(d). If EPA concludes that nothing in section 112(d) precludes this result, that section could provide a basis for EPA's final rule.

We note that implementing a cap and trade rule for Utility Units under section 112 could offer certain advantages as compared to our proposed section 111 approach. For example, EPA should be able to directly implement a national standard under section 112, instead of relying on the SIP-type approach required under section 111. As a result, a section 112 trading program would, among other things, reduce the administrative burdens on both EPA and the States and would assure national consistency.

The EPA invites public comment on all aspects of implementing a trading program under section 112. The EPA also requests comment on how it should design a trading program under section 112, including whether the title IV Acid Rain SO_2 program, the Acid Rain NO_X program, the NO_X SIP Call or today's proposed section 111 trading program are useful models for regulating Hg emissions.

In conjunction with this proposal to establish a cap-and-trade program under the authority of section 112(n)(1)(A) and/or 112(d), we also propose to revise the definition of ''emission standard'' in 40 CFR 63.2. We propose to amend the phrase ''pursuant to sections 112(d), 112(h), or 112(f) of the Act'' to include reference to section 112(n).

B. Summary of the Proposed Section 112 MACT Rule

1. What Is the Affected Source?

An existing affected source for the proposed rule is each group of coal- or oil-fired Utility Units located at a facility. A new affected source is a coal- or oil-fired Utility Unit for which construction or reconstruction began after January 30, 2004. The proposed rule defines a Utility Unit as:

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

If a unit burns coal (either as a primary fuel or as a supplementary fuel), or any combination of coal with another fuel, the unit is considered to be coal-fired under the proposed rule. If a unit is not a coal-fired unit and burns only oil, or oil in combination with natural gas (except as noted below), the unit is considered to be oil-fired under the proposed rule. If a new or existing unit burns natural gas exclusively or natural gas in combination with oil where the oil constitutes less than 2 percent of the unit's annual fuel consumption (used for start-up purposes), the unit is considered to be natural gas-fired and would not be subject to the proposed rule.

2. What Are the Proposed Emission Limitations?

The proposed rule would establish separate emissions limits for new and existing coal- and oil-fired Utility Units. For coal-fired units, limits would be established for Hg depending on the rank of coal. For oil-fired units, limits would be established for Ni emissions. The proposed limits for Hg for coal-fired units are expressed in pound per trillion British thermal unit (lb/TBtu) on an input basis or pound per Megawatt hour (lb/MWh) on an output basis. The proposed Ni limits for oil-fired units are expressed in lb/TBtu on an input basis or lb/MWh on an output basis. For both Hg and Ni, owners/operators of existing units would have the option of complying with either the input- or the output-based limit; owners/operators of new units would be subject to the output-based limit. The owner/operator would establish a unit-specific limit (according to methods provided in the proposed rule) for each coal-fired unit that burns blended coal. The proposed limits for coal-fired and oil-fired units are shown in Tables 1 and 2, respectively, of this preamble (for existing affected sources) and Tables 3 and 4, respectively, of this preamble (for new affected sources).

TABLE 1.—EMISSION LIMITS FOR EXISTING COAL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

Unit type	Hg (lb/TBtu) [1]		Hg (10^{-6} lb/MWh) [1]
Bituminous-fired [2]	2.0	or	21
Subbituminous-fired	5.8	or	61
Lignite-fired	9.2	or	98
IGCC unit	19	or	200
Coal refuse-fired	0.38	or	4.1

[1] Based on 12-month rolling average.
[2] Anthracite units are included with bituminous units.

TABLE 2.—EMISSION LIMITS FOR EXISTING OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

Unit type	Ni (lb/TBtu) [1]		Ni (lb/MWh) [1]
Oil-fired ..	210	or	0.002

[1] Based on do-not-exceed limit.

TABLE 3.—EMISSION LIMITS FOR NEW COAL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

Unit type	Hg (10^{-6} lb/MWh) [1]
Bituminous-fired [2]	6.0
Subbituminous-fired	20
Lignite-fired	62
IGCC unit	[3] 20
Coal refuse-fired	1.1

[1] Based on 12-month rolling average.
[2] Anthracite units are included with bituminous units.
[3] Based on 90 percent reduction for beyond-the-floor control.

TABLE 4.—EMISSION LIMITS FOR NEW OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

Unit type	Ni (lb/MWh) [1]
Oil-fired	0.0008

[1] Based on do-not-exceed limit.

Two alternatives for compliance purposes are provided in the proposed rule for oil-fired units. The owner/operator can elect to: (1) meet the Ni limit, or (2) burn distillate oil (exclusively) rather than residual oil. If an oil-fired unit is currently burning, or switches to burning, distillate oil (exclusively), it would be exempt from all oil-fired unit initial and continuous compliance requirements until such time as it begins burning any oil other than distillate oil. The proposed rule would require that the exempted oil-fired unit begin the performance testing procedures if it resumes burning a fuel other than distillate oil.

The proposed rule would also allow emissions averaging as a compliance option for existing coal-fired units located at a single contiguous plant. The owner/operator could elect to establish an overall Hg limit for an emissions averaging group using the procedures in the proposed rule and comply with that limit during each 12-month compliance period. The emissions averaging compliance approach is also applicable to coal-fired Utility Units subject to the Hg emission limits for new affected sources as long as they meet the new source limits.

The proposed emission limitations also include operating limits for control devices used to meet an emissions limitation. If an electrostatic precipitator (ESP) is used to meet a Ni limit, the owner/operator would be required to operate each ESP such that the hourly average voltage and secondary current (or total power input) do not fall below the limit established in the most recent performance test. Operating limits would not apply to control devices used to meet Hg emission limits where a continuous emission monitoring system (CEMS) or an appropriate long-term method is used to demonstrate compliance.

3. What Are the Proposed Testing and Initial Compliance Requirements?

New or reconstructed units must be in compliance with the applicable rule requirements upon initial startup or by the effective date of the final rule, whichever is later. Existing units must be in compliance with the applicable rule requirements no later than 3 years after the effective date of the final rule. The effective date is the date on which the final rule is published in the **Federal Register**.

Prior to the compliance date, the owner/operator would be required to prepare a unit-specific monitoring plan and submit the plan to the Administrator for approval. The proposed rule would require that the plan address certain aspects with regard to the monitoring system; installation, performance and equipment specifications; performance evaluations; operation and maintenance procedures; quality assurance techniques; and recordkeeping and reporting procedures. Beginning on the compliance date, the owner/operator would be required to comply with the plan requirements for each monitoring system.

Mercury emission limits. Compliance with the Hg emission limit would be determined based on a rolling 12-month average calculation. The Hg emissions are determined by continuously collecting Hg emission data from each affected unit by installing and operating a CEMS or an appropriate long-term method that can collect an uninterrupted, continuous sample of the Hg in the flue gases emitted from the unit. The proposed rule would allow the owner/operator to use any CEMS that meets requirements in Performance Specification 12A (PS–12A), ''Specifications and Test Procedures for Total Vapor-phase Mercury Continuous Monitoring Systems in Stationary Sources.'' An owner/operator electing to use long-term Hg monitoring would be required to comply using the new EPA Method 324, ''Determination of Vapor Phase Flue Gas Mercury Emissions from Stationary Sources Using Dry Sorbent Trap Sampling.'' Performance Specification 12A and Test Method 324 are proposed as part of this rulemaking. The owner/operator would use the procedures outlined in § 63.10009 of the proposed rule to convert the concentration output from a CEMS or Method 324 to an emission rate format in lb/TBtu or lb/MWh. The proposed rule would require the owner or operator to begin compliance monitoring on the compliance date.

For new or existing cogeneration units, steam is also generated for process use. The energy content of this process steam must also be considered in determining compliance with the output-based standard. Therefore, the owner/operator of a new or existing cogeneration unit would be required to calculate emission rates based on electrical output to the grid plus half the equivalent electrical output energy in the unit's process steam. The procedure for determining these Hg emission rates is included in § 63.10009(c) of the proposed rule.

The owner/operator of a new or existing coal-fired unit that burns a blend of fuels would develop a unit-specific Hg emission limitation and the unit Hg emission rate for the portion of the compliance period that the unit burned the blend of fuels. The procedure for determining these emission limitations is outlined in § 63.9990(a)(5) of the proposed rule.

Nickel emission limits. Compliance with the applicable Ni emission limits in the proposed rule would be determined by performance tests conducted according to the requirements in 40 CFR 63.7 of the NESHAP General Provisions and the requirements in the proposed rule. The proposed rule would require EPA Method 29 in appendix A to 40 CFR part 60 to be used for the measurement of Ni emissions in the flue gas. With Method 29, Method 1 would be used to select the sampling port location and the number of traverse points; Method 2 would be used to measure the volumetric flow rate; Method 3 would be used for gas analysis; and Method 4 would be used to determine stack gas moisture. Method 19 would be used to convert the Method 29 Ni measurements to an emission rate expressed in units of lb/TBtu if complying with an input-based standard. The owner/operator would use the procedures outlined in § 63.10009 of the proposed rule to convert the concentration output of

Method 29 to an emission rate format in lb/TBtu or lb/MWh.

The proposed rule would require the owner/operator to establish limits for control device operating parameters based on the actual values measured during each performance test. The proposed rule specifies the parameters to be monitored for the types of emission control systems commonly used in the industry. The owner/operator would be required to submit a monitoring plan identifying the operating parameters to be monitored for any control device used that is not specified in the proposed rule.

An initial performance test to demonstrate compliance with each applicable Ni emission limit would be required no later than 180 days after initial startup or 180 days after publication of the final rule, whichever is later, for a new or reconstructed unit, and no later than the compliance date for an existing unit (3 years after publication of the final rule).

The owner/operator of a new or existing cogeneration unit would have to account for the process steam portion of their emissions in the same manner for Ni emissions as they did for Hg emissions. The owner/operator of a cogeneration unit would be required to calculate the Ni emission rate based on electrical output to the grid plus half the equivalent electrical output energy in the unit's process steam (*see* section II.C.2 for an explanation of the basis for this approach). The procedure for determining these Ni emission rates are given in § 63.10009(c) of the proposed rule.

4. What Are the Proposed Continuous Compliance Requirements?

To demonstrate continuous compliance with the applicable emission limits under the proposed rule, the owner/operator would be required to perform continuous Hg emission monitoring for coal-fired units and continuous monitoring of appropriate operating parameters for the ESP used to comply with the Ni limit for oil-fired units. In addition, an annual performance test will be required for demonstrating compliance with the Ni emission limitation for oil-fired units. The annual performance test would be conducted in the same manner as the initial compliance demonstration.

5. What Are the Proposed Notification, Recordkeeping, and Reporting Requirements?

The proposed rule would require the owner/operator to keep records and file reports consistent with the notification, recordkeeping, and reporting requirements of the General Provisions of 40 CFR part 63, subpart A. Records required under the proposed rule would be kept for 5 years, with the 2 most recent years being on the facility premises. These records would include copies of all Hg emission monitoring data, coal usage, MWh generated, and heating value data required for compliance calculations; reports that have to be submitted to the responsible authority; control equipment inspection records; and monitoring data from control devices demonstrating that emission limitations are being maintained.

Two basic types of reports would be required: initial notifications and periodic reports. The owner/operator would be required to submit notifications described in the General Provisions (40 CFR part 63, subpart A), which include initial notification of applicability, notifications of performance tests, and notification of compliance status. For oil-fired units, if you at any time during the reporting period comply with an applicable emissions limit by switching fuel (in other than emergency situations), the proposed rule would also require that you notify EPA in writing at least 30 days prior to using a fuel other than distillate oil. In emergency situations, such notification must be within 30 days. As required by the General Provisions, the owner/operator would be required to submit a report of performance test results; develop and implement a written startup, shutdown, and malfunction plan and report semi-annually any events in which the plan was not followed; and submit semi-annual reports of any deviations when any monitored parameters fell outside the range of values established during the performance test.

C. Rationale for the Proposed Section 112 MACT Rule

1. How Did EPA Select the Affected Sources That Would Be Regulated Under the Proposed Rule?

As defined in section 112(a)(8) of the CAA, an ''electric utility steam generating unit'' means ''any fossil fuel fired combustion unit of more than 25 megawatts 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 megawatts electrical output to any utility power distribution system for sale shall be considered an electric utility steam generating unit.'' For purposes of this proposed standard, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy gross output capacity of the affected facility.

Only Utility Units that are fired by coal or oil, or combinations of fuels that include coal and oil, are subject to this proposal. Integrated gasification combined cycle units are also subject to this proposal. Boilers otherwise meeting the definition but fueled by gaseous fuels (other than gasified coal) at greater than or equal to 98 percent of their annual fuel consumption (when the other fuel burned is fuel oil or coal) are not included in the proposed rule.

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

Therefore, the first step towards rule development is to determine if dissimilarities between sources within the source category warrant subcategorization. Under CAA section 112(d)(1), which EPA is proposing to use for purposes of developing this rule pursuant to CAA section 112(n)(1)(A), the Administrator has the discretion to ''* * * distinguish among classes, types, and sizes of sources within a category or subcategory in establishing * * *'' standards.

Historically and as EPA noted in the December 2000 finding, the criteria used by EPA in evaluating differences in combustion sources for purposes of subcategorization have included the size of the facility, type of fuel used, and plant type. (65 FR 79830) The EPA also is free to consider other relevant factors, such as geographic factors, process design or operation, variations in emissions profiles, or differences in the feasibility of application of control technology (APCD or work practices).

For the coal- and oil-fired Utility Unit source category, the individual units or sources exhibited obvious and significant variations with regard to some of these criteria. The most prominent dissimilarity was that between coal- and oil-fired units. Coal- and oil-fired units have vastly different

emission characteristics due to their different fuels. The electric utility industry generally uses coal-fired units as base-loaded units (*i.e.*, the units are designed to run continuously except for maintenance intervals). Oil-fired units are generally used as ''peaking'' units (*i.e.*, the units are operated when extra electrical power is needed). Coal combustion produces higher emission levels of Hg than does a comparably sized oil-fired unit whereas oil combustion produces higher levels of Ni compounds. For these reasons, EPA divided sources into the initial subcategories of coal- and oil-fired units. Additional evaluation of the data was then conducted to ascertain if further subcategorization within coal-fired or within oil-fired units was warranted.

Subcategorization within existing coal-fired units. The American Society for Testing and Materials (ASTM) classifies coals by rank, a term which relates to the carbon content of the coal and other related parameters such as volatile-matter content, heating value, and agglomerating properties. The coal-fired electric utility industry combusts the following coal ranks, presented in decreasing order: anthracite, bituminous, subbituminous, and lignite. The higher heating value (HHV) of coal is measured as the gross calorific value, reported in British thermal units per pound (Btu/lb). The heating value of coal increases with increasing coal rank. The youngest, or lowest rank, coals are termed lignite. Lignites have the lowest heating value of the coals typically used in power plants. Their moisture content can be as high as 30 percent, but their volatile content is also high; consequently, they ignite easily. Next in rank are subbituminous coals, which also have a relatively high moisture content, typically ranging from 15 to 30 percent. Subbituminous coals also are high in volatile matter content and ignite easily. Their heating value is generally in between that of the lignites and the bituminous coals. Bituminous coals are next in rank, with higher heating values and lower moisture and volatile content than the subbituminous and lignite coals. Anthracites are the highest rank coals. Because of the difficulty in obtaining and igniting anthracite and the difficulties in maintaining anthracite-fired boilers, only a single electric utility boiler in the U.S. burned anthracite as its only fuel in 1999. Because bituminous coal is the most similar coal to anthracite coal based on coal physical characteristics (ash content, sulfur content, HHV), anthracite coal is considered to be equivalent to bituminous coal for the purposes of the proposed rule and, thus, the anthracite-fired unit is considered a bituminous-fired unit for the purposes of the proposed rule.

Although there is overlap in some of the ASTM classification properties, the ASTM method of classifying coals by rank has been in use for decades and generally is successful in identifying some common core characteristics that have implications for power plant design and operation.

Coal refuse (*i.e.*, anthracite coal refuse (culm), bituminous coal refuse (gob), and subbituminous coal refuse) is also combusted in Utility Units. Coal refuse refers to the waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material. Previously considered unusable by the industry because of the high ash content and relatively low heat content, it now may be utilized as a supplemental fuel in limited amounts in some units or as the primary fuel in a fluidized bed combustor (FBC). Because of the inherent inability to utilize coal refuse as the primary fuel in anything other than an FBC, it is considered to be a separate coal rank for purposes of the proposed rule.

The rank of coal to be burned has a significant impact on overall plant design. The goal of the plant designer is to arrange boiler components (furnace, superheater, reheater, boiler bank, economizer, and air heater) to provide the rated steam flow, maximize thermal efficiency, and minimize cost. Engineering calculations are used to determine the optimum positioning and sizing of these components, which cool the flue gas and generate the superheated steam. The accuracy of the parameters specified by the owner/operators is critical to designing and building an optimally efficient plant. The rank of coal to be burned greatly impacts the entire design process. The rank of coal burned also has significant impact on the design and operation of the emission control equipment (*e.g.*, ash resistivity impacts ESP performance).

For the above reasons, one of the most important factors in modern electric utility boiler design involves the differences in the ranks and range of coals to be fired and their impact on the details and overall arrangement of boiler components. Coal rank is so important that plant designers and manufacturers expect to be provided with a complete list of all coal ranks presently available or planned for future use, along with their complete chemical and ash analyses, so that the engineers can properly design and specify plant equipment. The various coal characteristics (*e.g.*, how hard the coal is to pulverize; how high its ash content; the chemical content of the ash; how the ash ''slags'' (fused deposits or resolidified molten material that forms primarily on furnace walls or other surfaces exposed predominantly to radiant heat or high temperature); how big the boiler has to be to adequately utilize the heat content; etc.), therefore, affect design from the pulverizer through the boiler to the final steam tubes. For a boiler to operate efficiently, it is critical to recognize the differences in coals and make the necessary modifications in boiler components during design to provide optimum conditions for efficient combustion.

Coal-fired units are designed and constructed with different process configurations partially because of the constraints, including the properties of the fuel to be used, placed on the initial design of the unit. Accordingly, these site-specific constraints dictate the process equipment selected, the component order, the materials of construction, and the operating conditions.

Approximately 23 percent of coal-fired Utility Units either (1) co-fire two or more ranks of coal (with or without other fuels) in the same boiler, or (2) fire two or more ranks of coal (with or without other fuels) in the same boiler at different times (1999 EPA ICR). This coal ''blending'' is done generally for one of three reasons: (1) to achieve SO_2 emission compliance with title IV provisions of the CAA, (2) to prevent excessive slagging by improving the heat content of a lower grade coal, or (3) for economic reasons (*i.e.*, coal rank price and availability).

These blended coals, although of different rank, do have similar properties. That is, because of the overlap in various characteristics in the ASTM definitions of coal rank, certain bituminous and subbituminous coals (for example) exhibit similar handling and combustion properties. Plant designers and operators have learned to accommodate these blends in certain circumstances without significant impact on plant operation or control.

There are five basic types of coal combustion processes used in the coal-fired electric utility industry. These are conventional-fired boilers, stoker-fired boilers, cyclone-fired boilers, IGCC units, and FBC units.

Conventional boilers, also known as pulverized coal (PC) boilers, have a number of firing configurations based on their burner placement. The basic

characteristic that all conventional boilers have in common is that they inject PC and primary air through a burner where ignition of the PC occurs, which in turn creates an individual flame. Conventional boilers fire through many such burners mounted in the furnace walls.

In stoker-fired boilers, fuel is deposited on a moving or stationary grate or spread mechanically or pneumatically from points usually 10 to 20 feet above the grate. The process utilizes both the combustion of fine coal powder in air and the combustion of larger particles that fall and burn in the fuel bed on the grate.

Cyclone-fired boilers use several water-cooled horizontal burners that produce high-temperature flames that circulate in a cyclonic pattern. The burner design and placement cause the coal ash to become a molten slag that is collected below the furnace.

Fluidized bed combustors combust coal, in a bed of inert material (*e.g.*, sand, silica, alumina, or ash) and/or a sorbent such as limestone, that is suspended through the action of primary combustion air distributed below the combustor floor. ''Fluidized'' refers to the state of the bed of material (coal and inert material (or sorbent)) as gas passes through the bed. As the gas flow rate is increased, the force on the fuel particles becomes just sufficient to cause buoyancy. The gas cushion between the solids allows the particles to move freely, giving the bed a liquid-like (or fluidized) characteristic.

Integrated-coal gasification combined cycle units are specialized units in which coal is first converted into synthetic coal gas. In this conversion process, the carbon in the coal reacts with water to produce hydrogen gas and carbon monoxide (CO). The synthetic coal gas (syngas) is then combusted in a combustion turbine which drives an electric generator. Hot gases from the combustion turbine then pass through a waste heat boiler to produce steam. This steam is fed to a steam turbine connected to a second electric generator.

After examining a number of possible subcategorization options, EPA identified three basic ways to subcategorize coal-fired Utility Units.

No subcategorization. This approach would treat all coal ranks and all coal combustion process types as one, with the MACT floor developed using all of the coal-fired unit data.

Subcategorization by coal rank. Subcategorization by individual coal rank accommodates the various design and control constraints resulting from the various coal ranks.

Subcategorization by process type. Another option is to subcategorize by process type (*e.g.*, stoker-fired, cyclone-fired, FBC, IGCC).

To determine the appropriate subcategorization approach, the EPA evaluated fuel, process, and control technology and found that the data did not identify any common attribute among the top units that could be credited with the demonstrated better performance. The EPA found that each of the best-performing units had a combination of factors that was the basis for the better performance on that particular unit. The factors identified included the Hg and chlorine (Cl) contents of the coal, the speciation of the Hg in the flue gas stream, and the control device configuration.

Based on this information, EPA then analyzed the available data to determine which coal ranks were burned, and why, to ascertain if changing coal rank would be a conceivable control strategy. The EPA found that the characteristics of the coal rank to be burned was the driving factor in how a coal-fired unit was designed. Further, the choice of coal ranks to be burned for a given unit is based on economic issues, including availability of the coal within the region or locale. A number of coal-fired units, including all known lignite-fired units, are ''mine mouth'' (or near mine-mouth) operations (*i.e.*, the unit is constructed on or near the coal mine itself with coal transport often being done by conveyor directly from the mine) and many do not have the infrastructure in place (*e.g.*, interstate rail lines) to import other ranks of coal in quantities sufficient to replace all lignite coal combusted. The EPA also found that substitution of coal rank, in most cases, would require significant modification or retooling of a unit, which would indicate a pertinent difference in the design/operation of the units. Because not all units are designed to combust the same rank of coal and the Hg emissions from some ranks of coal are easier to control than those from other ranks, a standard based on ''no subcategorization'' likely would be unachievable for some units. For these reasons, EPA decided that subcategorization of coal-fired units based on coal rank (fuel type) was warranted. We note again that certain Utility Units are, in fact, able to effectively combust coals from different ASTM ranks because of the overlap in coal classification properties. We do not, however, believe that this ''overlap'' compromises our ability to subcategorize by coal rank because it remains true that coal rank is a significant factor that distinguishes the design and operational characteristics of different boilers. We ask for comment on this issue.

Although conventional-, stoker-, and cyclone-fired boilers use different firing techniques, the Hg emissions characteristics of these boilers are similar (when common ranks of coal are fired) and, therefore, the units can be grouped together and further subcategorization by these process types is not necessary.

Based on their unique firing designs, FBC units employ a fundamentally different process for combusting coal from that employed by conventional-, stoker-, or cyclone-fired boilers. Fluidized-bed combustors are capable of combusting many coal ranks, including coal refuse. For these reasons, FBC units can be considered a distinct type of boiler. However, the Hg emissions test data results for FBC units were not substantially different from those at similarly-fueled conventionally-fired units with similar emission levels, either in mass of emissions or in emissions characteristics. Therefore, EPA has decided not to establish a separate subcategory for FBC units.

Integrated gasification combined cycle units combust a synthetic coal gas. No coal is directly combusted in the unit during operation (although a coal-derived fuel is fired), and, thus, IGCC units are a distinct class or type of boiler for the proposed rule.

For the purposes of the proposed rule and based on the above information, the coal-fired units at existing affected sources are subcategorized into five subcategories, four based on coal rank and one based on process type: bituminous (including anthracite); subbituminous; lignite; coal refuse (which includes anthracite coal refuse (culm), bituminous coal refuse (gob), and subbituminous coal refuse); and IGCC (coal syngas). Because few units fire anthracite coal and because there are significant similarities in the emissions resulting from the combustion of anthracite and bituminous coals, EPA chose to combine anthracite coal with bituminous coal for the purposes of this rule. A more detailed description of the specific elements and rationale used to determine this subcategorization scheme is located in the docket.

Subcategorization within existing oil-fired units. The EPA analyzed the data available on the fuel, process, emission profiles, and APCD for oil-fired units at existing affected sources. An oil-fired electric utility boiler combusts fuel oil exclusively, or combusts fuel oil at certain times of the year and natural gas at other times (not simultaneously). The choice of when to combust oil

exclusively or to alternate between oil and natural gas at a single boiler is usually based on economics or fuel availability (including seasonal availability). The ASTM classifies oils by ''grade,'' a term which relates to the amount of refinement that the oil undergoes. The level of refinement directly affects the Ni and carbon content of the oil and other related parameters such as sulfur content, heating value, and specific gravity. The most refined fuel oil used by the oil-fired electric utility industry is known as No. 2 fuel oil (also known as distillate oil or medium domestic fuel oil). The least refined fuel oil used by the oil-fired electric utility industry is known as No. 6 fuel oil (also known as residual oil or Bunker C oil). By comparison, No. 2 fuel oil is lower in Ni, sulfur, ash content, and heating value but higher in carbon content than No. 6 fuel oil. Only a handful of boilers (8 of 218) fire No. 2 distillate fuel oil exclusively. (2001 EIA data) However, 28 out of 218 boilers fire No. 2 distillate fuel oil and No. 6 (residual) fuel oil in the same boiler (either simultaneously or at separate times).

The type of oil to be burned has little impact on overall boiler design. The goal of the plant designer is to make sure the plant can handle the different viscosities of oil (and natural gas if applicable) that the boiler is likely to combust.

There is only one basic type of oil combustion process used in the oil-fired electric utility industry, known as a conventional-fired boiler. Conventional-fired boilers have a number of firing configurations based on their burner placement. The basic characteristic that all conventional-fired boilers have in common is that they inject oil and primary air through a burner where ignition of the oil occurs, which in turn creates an individual flame. Conventional-fired boilers fire through many such burners mounted in the furnace walls.

The data available to EPA indicated that there is very little variation in the process or control technologies used in the industry. Therefore, EPA found no criteria that would warrant further subcategorization within existing oil-fired units and is not doing so in the proposed rule.

Subcategorization within new units. With regard to new sources, EPA has no data that indicate that the rationale for subcategorization for existing coal-fired units would not be applicable to new units (*i.e.,* there is no reason to believe that new units will not utilize the full range of coal ranks and combustion process types currently used by existing units). New units constructed at the same facilities as existing units could still be restricted, at least in concept, to the same physical constraints (*e.g.,* coal handling and processing, access to interstate rail lines) as are the co-located existing units. Further, EPA has no data indicating the availability of existing coal ranks is likely to substantially change for a given locale. For this reason, EPA is proposing that the subcategorization scheme for new coal- and oil-fired units be the same as for the existing units.

The EPA solicits comment on this decision that new and existing units should be subcategorized in the same manner.

2. How Did EPA Select the Format of the Proposed Emission Standards?

The EPA has established pollution prevention as one of the its highest priorities. One of the opportunities for pollution prevention lies in simply using energy efficient technologies to minimize the generation of emissions. The EPA has previously investigated ways to promote energy efficiency in utility plants by changing the manner in which it regulates flue gas emissions. Therefore, in an effort to promote energy efficiency in utility steam generating facilities, the Administrator is proposing output-based standards for new sources for emissions of Hg and Ni under this rule. This format has been used successfully on other EPA rules (*e.g.,* subpart Da NSPS NO_X, 40 CFR 63.44a). Existing sources would have the option of using either input- or output-based limits based on the potential increase in cost resulting from the need to add instrumentation.

Traditionally, utility emissions have been controlled on the basis of boiler input energy (lb/million British thermal units (MMBtu) heat input). However, input-based limitations allow units with low operating efficiency to emit more per megawatt (MWe) of electricity produced than more efficient units. Considering two units of equal capacity, under current regulations, the less efficient unit will emit more because it uses more fuel to produce the same amount of electricity. One way to regulate mass emissions and plant efficiency is to express the emission standard in terms of output energy. Thus, an output-based emission standard would provide a regulatory incentive to enhance unit operating efficiency and reduce emissions. Two of the possible output-based formats considered for the revised standards were: (1) Mass emitted per gross boiler steam output (lb/TBtu heat output), and (2) mass emitted per net energy output (lb/MWh). The criteria used for selecting the format were ease in monitoring and compliance testing and ability to promote energy efficiency.

The objective of an output-based standard is to establish an emission limit in a format that incorporates the effects of plant efficiency. Additionally, the limit should be in a format that is practical to implement. Thus, the format selected must satisfy the following: (1) Provide flexibility in promotion of plant efficiency; (2) permit measurement of parameters related to stack emissions and plant efficiency, on a continuous basis; and (3) be suitable for equitable application on a variety of power plant configurations.

The option of lb/TBtu steam output accounts only for boiler efficiency, ignores both the turbine cycle efficiency and the effects of energy consumption internal to the plant, and provides minimal opportunities for promoting energy efficiency at the units. The EPA has found that the second output-based format option of lb/MWh is preferable as it accounts for all aspects of efficiency and provides opportunity for promoting energy efficiency for the units.

The format of lb/MWh can be measured in two ways: net and gross energy output. The net plant energy output provides the owners/operators with all possible opportunities for promoting energy efficiency and can easily accommodate both electrical and thermal (process steam) outputs. The disadvantage of a net plant energy output is that implementation could require significant and costly additional monitoring and reporting systems because the energy output that is used for internal components (and not sent to the grid) cannot be accounted for by simply installing another meter. The gross plant energy output, on the other hand, represents the energy generated before any internal energy consumption and losses are considered. Rules based on this format do not have the disadvantages of the net-based format mentioned above.

Based on this analysis, an emission limit format based on mass of emissions per gross plant energy output is selected for the proposed output-based standard. Because electrical output at all power plants is typically measured directly in MWe, a format in ''lb/MWh gross'' is determined to be the most appropriate for the proposed rule. The EPA, however, requests comments on the selected format of ''lb/MWh gross'' because a format of ''lb/MWh net'' may be more productive in encouraging overall energy efficiency at electric utility plants.

Compliance with the output-based emission limit would require continuous measurement of plant operating parameters associated with the mass rate of emissions and gross energy outputs. In the case of cogeneration plants where process steam is an output product, means would have to be provided to measure the process steam flow conditions and to determine the useful heat energy portion of the process steam that is interchangeable with electrical output.

Instrumentation already exists in power plants to conduct these measurements since the instrumentation is required to support current emission regulations and normal plant operation. Consequently, compliance with the output-based emission limit is not expected to require any additional instrumentation. Therefore, no additional instrumentation is required for conventional utility applications (particularly for new sources) to comply with the output-based emission limit. However, additional signal input wiring and programming is expected to be required to convert the above measurements into the compliance format (lb/MWh gross).

To use an output-based standard for cogeneration units (*i.e.,* units which use steam to both generate electricity and as a process input), the energy content of the process steam must also be considered in determining compliance with the output-based standard. The EPA has determined that existing plant monitoring and energy calculation curves are available and can be easily programmed to determine the steam's equivalent electrical energy component. This component can then be added to the plant's actual gross electrical output to arrive at the plant's total gross energy output.

Since all the reported data obtained throughout the development of the revised standards are in the current format of lb/TBtu heat input, EPA applied an efficiency factor to the current format to develop the output-based limits. The efficiency factor approach was selected because the alternative of converting all the reported data in the database to an output-basis would require extensive data gathering and analyses. Applying a baseline efficiency would essentially convert the selected heat input-based level to an output-based emission limit.

The output-based standard must be referenced to a baseline efficiency. Most existing electric utility steam generating plants fall in the range of 24 to 35 percent efficiency. However, newer units operate around 35 percent efficiency; therefore, 35 percent was selected as the baseline efficiency for new units; 32 percent was selected as the baseline efficiency for existing units. The EPA requests comment on: (1) Whether 35 percent is an appropriate baseline efficiency, (2) how often the baseline efficiency should be reviewed and revised in order to account for future improvements in electric generation technology, and (3) the specific methodology or methodologies appropriate and verifiable for determining the gross energy output.

The efficiency of Utility Units usually is expressed in terms of heat rate, which is the ratio of heat input, based on HHV of the fuel, to the energy (*i.e.,* electrical) output. The heat rate of a utility steam generating unit operating at 32 percent efficiency is 11 joules per watt hour (J/Wh) (10,667 Btu per kilowatt hour (kWh)); at 35 percent efficiency, the values are 10 J/Wh (9,833 Btu/kWh).

Determination of the gross efficiency of a cogeneration unit includes the gross electrical output and the useful work achieved by the energy (*i.e.,* steam) delivered to an industrial process. Under a Federal Energy Regulatory Commission (FERC) regulation, the efficiency of cogeneration units is determined from ''* * * the useful power output plus one-half the useful thermal output * * *,'' 18 CFR part 292, section 205. Therefore, to determine the process steam energy contribution to net plant output, a 50 percent credit of the process steam heat was selected. This approach is consistent with the approach taken in the most recent subpart Da revision to the NO_X standard.

The proposed section 112 MACT rule does not include a specific methodology or methodologies for determining the unit gross output. The EPA would specify such methods in the final rule.

The proposed format for Hg also includes the use of a 12-month rolling average in determining compliance. The EPA considers use of an averaging period to be appropriate because Hg is not an acute health hazard in the context of its emission from Utility Units. Rather, it is a persistent bioaccumulative HAP that lends itself to monitoring over a longer-term period. Several periods could be used for this purpose, including 12-month rolling, quarterly, and yearly. Electric Utility Units already monitor their fuel use on a monthly basis for reporting to the DOE. Therefore, EPA is proposing to base the Hg standard on a 12-month rolling average period.

The EPA requests comment on all aspects of the analyses and conclusions set forth above, including (1) whether 32 and 35 percent are appropriate baseline efficiencies; (2) how often the baseline efficiency should be reviewed and revised in order to account for future improvements in electric generation technology; (3) whether the output-based standard option in the proposed rule will promote energy efficiency improvements; (4) the specific methodology or methodologies appropriate and verifiable for determining the gross output of a steam generating unit; and (5) whether a fixed percentage credit of 50 percent is representative of the useful heat in varying quality of process steam flows.

3. How Did EPA Determine the Proposed MACT Floor for Existing Units?

All standards established pursuant to the process set forth in section 112(d) of the CAA must reflect the maximum degree of reduction in emissions of HAP that is determined to be achievable by the industry source category. For existing sources, MACT cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources for categories and subcategories with 30 or more sources (excluding certain sources as specified by the CAA). This level of control is known as the MACT floor. Because the MACT floor represents the level of reduction in HAP emissions that is actually achieved by the best-performing sources in the source category, EPA may not consider cost and other impacts in determining the MACT floor.

This section describes the process used by EPA to determine the MACT floors for each of the subcategories included in the coal- and oil-fired electric utility source category. The MACT floor determination process for this source category was complicated by the many ranks/grades of fossil fuels used in the industry and the capability of the air pollution control technologies currently used in the industry to reduce Hg and Ni emissions.

The initial step in developing a MACT floor or floors for a source category is determining whether subcategorization is appropriate. A discussion of EPA's analysis and conclusions concerning subcategorization of coal-fired units is set forth above.

One potential approach for establishing MACT floors for the subcategories is to require all of the sources in a category to implement precombustion pollution prevention measures. The precombustion techniques include fuel substitution, process changes, and work practices. As discussed in detail below, EPA has

determined that none of these approaches are viable for all of the units in the coal- and oil-fired electric utility source category.

Did EPA consider the use of precombustion measures in establishing the MACT floor? The EPA first considered the feasibility of fuel substitution from several perspectives: (1) Switching to other fuels used in the same subcategory (*e.g.*, a ''lower'' Hg content bituminous coal); (2) switching to fuels used in another subcategory (*e.g.*, firing bituminous coal instead of lignite coal); or (3) switching to natural gas. The EPA considered several aspects of fuel switching in evaluating these alternatives. These aspects included whether switching fuels would achieve lower Hg and Ni emissions, whether fuel switching could be technically achieved considering the existing design characteristics of electric Utility Units, and the availability of various types of fuel.

For coal-fired units, the first aspect considered was fuel switching either to a better (or lower Hg-containing) seam of coal used within a subcategory or used in another subcategory. The question of whether switching between coals is a viable option arises from the variation in Hg content and other key attributes in different seams of coal. The data indicate that, although one seam may have less Hg than another, it may be higher in other chemical constituents of concern. The EPA has no data on which to determine the ''best'' seam, or rank, of coal on which to base such a requirement. Further, even if a ''better/best'' seam could be identified, changing to a specific or different seam of coal would essentially determine the area or even mine from which the coal could be produced. The fuel substitution issue then becomes dependent on the regional differences in coal characteristics and the subsequent feasibility of placing a burden on units that are located further from the better/best seams. The EPA feels that the intent of the CAA is to develop standards that, to the greatest extent reasonably possible, are consistent across the industry and avoid actions that create regional disparities. The EPA further feels that requiring all plants to combust coal from a specific seam is not a viable long-term solution because the supply of coal from that seam would be rapidly depleted. Finally, EPA has determined (as stated earlier) that the existing Utility Units were designed based on the availability of certain coal ranks and has found that, in some instances, the units were actually co-located with a particular coal source.

Another perceived use of alternate ranks or seams of coal is to use clean coal. The term ''clean coal'' generally refers to a fuel that is lower in sulfur and/or ash content. Data gathered by EPA indicate that within specific coal ranks, the Hg content can vary significantly and that lower sulfur content does not necessarily mean lower Hg content.

Certain physical characteristics of coal-fired units also limit the effectiveness of prevention measures. A unit may require extensive changes to the coal handling and feeding system (*e.g.*, a stoker using bituminous coal as fuel would need to be redesigned) in order to burn a different rank of coal. Additionally, existing burners and combustion chamber designs are generally not capable of handling different coal ranks, and generally cannot accommodate increases or decreases in the coal volume and shape. For example, burners are designed partially on the hardness of the coal; changing coal ranks could result in a harder coal and increased wear on the burners. The size of the burner and combustion chamber are based, in part, on the heating value of the coal rank; lower rank coals require larger systems for the same amount of heat input. Design changes to allow different coal use may, in some cases, reduce the capacity and efficiency of the unit. Reduced efficiency results in a lack of effective energy usage and may result in less complete combustion and, thus, an increase in emissions.

Another factor supporting EPA's conclusion that precombustion measures are not a viable emissions reductions approach for all units in the category is the lack of available alternative types of fuel for a given unit. Natural gas pipelines are not available in all regions of the U.S. Even where pipelines provide access to natural gas, supplies of natural gas may not be available in adequate quantities for utilities. For example, it is common practice in large metropolitan areas during winter months (or periods of peak demand) to prioritize natural gas usage for residential areas before industrial areas (*i.e.*, natural gas curtailments). Requiring an EPA-regulated utility unit to switch to natural gas would place an even greater strain on natural gas resources, and, in some circumstances, the change would interfere with a unit's ability to run at full capacity. For these reasons, EPA decided that fuel switching is not an appropriate criterion for identifying the MACT floor level of control for existing coal-fired units.

With regard to process changes, EPA found that Hg and Ni emissions of concern from coal- and oil-fired units are primarily dependent upon the composition of the fuel and, to a lesser extent, the combustion process. Consequently, process changes (*i.e.*, changes to unit design/operation) would be ineffective in reducing these fuel-related Hg and Ni emissions. The EPA did not identify any process changes or work practices that would be appropriate criteria for identifying the MACT floor level of control for existing coal- or oil-fired units.

In general, electric Utility Units are designed for efficient combustion. Facilities have an economic incentive to ensure that fuel is not wasted and that the combustion device operates properly and is appropriately maintained. In fact, historical data show that the average heat rate (*i.e.*, heat energy required to produce 1 kWh of electricity) declined by 11-fold between 1899 and the mid-1960s, mainly because of the desire to run efficient plants. The EPA was also unable to identify any uniform requirements or set of work practices that would meaningfully reflect the use of GCP or that could be meaningfully implemented across any subcategory of units. Therefore, EPA has not found combustion practice requirements useful in determining the MACT floor for existing coal- or oil-fired units. However, EPA's inability to establish a combustion practice requirement as part of the MACT floor for existing units does not reduce the incentive for owners/operators to operate their units at top efficiency.

The EPA requests comments and emissions information regarding whether there are any uniform GCP for controlling Hg and Ni that would be appropriate for minimizing Hg and Ni emissions from any subcategory of electric Utility Units.

4. How Did EPA Derive the MACT Floor for Each Subcategory?

As noted above, the EPA has determined that coal rank and resulting system design characteristics warrant subcategorization within coal-fired units. Once EPA determined that precombustion techniques were not helpful in determining the MACT floor for the entire source category, the next step was to develop a MACT floor for each subcategory based on the control technology used by the top-performing units (*i.e.,* equipment based), and the level of emissions reductions (*i.e.,* emission limitation based) that the top units in each subcategory demonstrated.

The EPA had data from an evaluation of the Hg control performance of various emission control technologies that are either currently in use on coal-fired units (designed for pollutants other than Hg) or that could be applied to such units for Hg control. According to the available data, none of the existing control systems were specifically designed to remove Hg; however, most of the controls removed Hg to some degree. The most prevalent control technology used in the industry was the ESP, which was designed to control PM. Fabric filters or the combination of spray dryer adsorbers (SDA) and fabric filters were, however, found to be the most effective control technology for Hg removal generally.

Unfortunately, the best Hg control technology scenarios were not consistent with regard to the extent to which they removed Hg. For these reasons, EPA decided to address Hg under the proposed rule using an emission limitation-based approach as opposed to a control equipment-based approach.

As a result of the preceding evaluations, EPA concluded that the most appropriate approach for determining MACT floors for existing coal- and oil-fired units was to rank the emission test results from units within each subcategory from lowest to highest and calculate a MACT floor emission limitation by taking the numerical average of the test results from the best-performing 12 percent (or equivalent) of affected sources. The MACT floor database consisted of all pollutants described in the 132 test reports, including multiple runs if they were available. Units were ranked based on the subcategorization scheme described elsewhere in this preamble, and then ranked from lowest to highest by Hg emission rates within each subcategory. For oil-fired units, the ranking process was based on the Ni emission rates.

5. How Did EPA Account for Variability?

In establishing the MACT floor(s) for existing sources in a particular category or subcategory of sources, section 112(d)(3) of the CAA calls for EPA to determine the average level of emission limitation actually being achieved by the best-performing existing sources in that category or subcategory. For combustion sources such as Utility Units, variability in both the Hg or Ni content of the fuel combusted and the performance of a particular control device have a significant impact on the determination of the level of emission limitation actually being achieved. As a result, it is essential that EPA be able to identify and quantify the level of variability arising from these sources. This is borne out by the test report data EPA obtained through the ICR. That data, which EPA is confident are representative of the industry, shows a significant degree of variability, even within a given subcategory. The EPA, therefore, decided it was necessary to develop a methodology to address the multiple sources of the observed variability in order to assure that an emission limitation value could be derived that was representative of what was actually being achieved by the best-performing units under all conditions expected to be encountered by those units. The origins of variability and approaches available for addressing the variability found in the test data are described below.

Variability is inherent whenever measurements are made or whenever mechanical processes operate. Variability in emission test data may arise from one or more of the following areas: (1) The emission test method(s); (2) the analytical method(s); (3) the design of the unit and control device(s); (4) the operation of the unit and control device(s); (5) the amount of the constituent being tested in the fuel; and, (6) composition of the constituents in the fuel and/or stack gases.

Test and analytical method variability can be quantified by statistical analysis of the results of a series of tests. The results can be analyzed to establish confidence intervals within which the true value of a test result is presumed to lie. Confidence intervals can be estimated for multiple-run series of tests based on the differences found from one test run to the next, with only the upper confidence interval having meaning (signifying the chance of the standard being exceeded).

When testing is done at more than one unit, similar confidence intervals can be established to account for the variability from unit-to-unit. One can combine the test-to-test and unit-to-unit variability into a single factor that can be applied to reported test values to give an upper limit for the likely true value. One can also estimate the combined factor for any desired confidence level.

Another source of variability is the time interval during which the test is being conducted. Testing for a short time may not reveal the range of emissions that would be found over extended time periods. Normal changes in operating conditions or in fuel characteristics may affect emission levels over time. For example, an increase in the Hg or Ni content of the fuel being fired in a unit may tend to increase the Hg or Ni emission rate from the associated stack, even where the control efficiency of the APCD remains constant. Mercury emission rates may also change with unit loads due to changes in the gas flow rate through APCD downstream from the unit which may affect APCD effectiveness.

Variability in control efficiency or emission rates may be addressed in a number of ways, depending on the circumstances existing within the source category. For example, different test run results can be analyzed statistically to arrive at an upper limit that represents the highest likely value for each test planned for use in setting emission limits. The poorest-performing (worst-case) unit in the top 12 percent of each subcategory can be reviewed to determine the causes of poor performance. A factor, which when applied to each of the test runs, can more accurately reflect performance over the full range of operating conditions can then be developed. This results in emission values that would not likely be exceeded over long time periods. Another approach is to look only at the performance of control devices used by sources in the top 12 percent and then use that information to determine likely emissions reductions for different devices operating on different units firing different fuels. The range in emissions reductions derived in this manner could then be used to set upper limits of expected control performance (*i.e.,* to identify the best performance that can be expected under the worst conditions); then, these limits could be used, as above, to set emission limitations for each subcategory. A third approach is to identify correlations between constituents of concern and other, perhaps more easily measured, constituents that can be used to develop algorithms that incorporate variability.

In the context of developing a MACT standard, the issue of how to appropriately address variability arises in deriving the MACT floor level of control. In order to determine the average emission limitation actually being achieved by the best-performing sources in a category or subcategory, EPA must determine how those sources will perform over the full range of operating conditions they can reasonably be anticipated to encounter. Addressing variability in the MACT floor calculation requires that all of the origins of variability be assessed and quantified into factors that can be incorporated into the emission limitation calculations for each subcategory's floor. In this way, the actual performance of each of the floor units over the full range of operating conditions can be derived. The result of

this approach is that the measured emission rate for each unit used for floor calculations is increased to account for the variability found from statistical analysis, worst-case analysis, or control device performance analysis. The performance of each unit in the top 12 percent of its subcategory would be adjusted to reflect the uncertainty associated with the various origins of variability, and the average emission rate for these units would be used as the floor emission limitation.

In trying to address the apparent sources of variability in the emissions test data, EPA tried to obtain data that reflected as many different plant configurations as would be found in the entire industry profile and, through the ICR, required tests to be conducted at units believed to be representative of the various plant configurations and operating conditions found within the source category. The tests and measurements, typically a three-run series of manual samples taken over 1 or 2 days of testing, are limited by the emission test method's accuracy and precision, by the short duration of the test, and by differences from one run to the next and one unit to the next. Together, these factors bring into question the accuracy of the results of the tests as a measure of a particular units performance over time. The EPA has evaluated the total population of test results to determine a valid test method variability factor for each type of control device as well a worst-case fuel variability factor. The EPA determined that it was necessary to evaluate the total population of test results to ensure that the resulting variability factors were an accurate predictor of the impacts of variability on the performance of the floor facilities. The variability factors were then applied in MACT floor emission limitation calculations, as appropriate. Applying these variability factors to the identified performance of the floor facilities, EPA has developed proposed emission limits for Hg for coal-fired Utility Units and for Ni for oil-fired Utility Units. Information contained in the docket provides a detailed description of the analysis of the variability issues, including the methods available and used to address the variability in test data used for the proposed rule.

How did EPA derive the proposed MACT floor emission limitations for existing sources? In order to determine the MACT floor emission limits for existing units, EPA examined the population database of existing sources. Available emissions test data were divided according to the subcategorization scheme described elsewhere in this preamble; first coal- and oil-fired, then the five subcategories of coal-fired units. The EPA examined the existing emission test data to determine the individual numerical average of the test results from the best-performing 12 percent (or equivalent) of each subcategory for Hg or Ni. The EPA then applied the potential uncertainty and variability factors to derive the MACT floor limits. All test data were provided to EPA in an input-based format (lb/TBtu). Therefore, EPA conducted all MACT floor calculations using the input-based format and then converted the input-based format into an output-based format (lb/MWh) as a compliance option, according to the approach described elsewhere in this preamble. The discussion below describes the development of the emission limitation for each subcategory in the electric utility source category.

The EPA initiated the evaluation of the units within each subcategory by ranking them from lowest to highest based on emission rates representing the outlet Hg or Ni concentration of the stack tests. This initial evaluation of the test report data indicated that no specific control technology or combination of technologies could be credited with the better performance; however, the evaluation indicated that fabric filter technology did provide a degree of Hg removal and that ESP units also provided a degree of removal, although to a less consistent and lower degree than did fabric filter units. The EPA further investigated the apparent inconsistency of Hg removal and found that the level of removal of Hg was dependent on the speciated form of Hg as presented to the control device. This phenomenon was further evaluated using the entire database of coal-fired units to determine if the variations in the control device performances could be correlated to the speciated form of the Hg presented to the APCD. This evaluation encompassed an evaluation of existing coal-fired units from the ICR data that provided Hg speciation data, Hg-in-coal data, and pre- and post-last-control unit emissions test data. The data indicated that where Hg was presented to the control device in particulate-bound form, both fabric filter and ESP devices provided a degree of control, with fabric filters generally performing better than ESP units. Where Hg was presented to the control device in an elemental form, the performance of the various control devices was highly variable. Part of the variation is believed to be attributable to the form of Hg in the flue gas, such as chlorine compounds. However, part of the variation is not understood at this time, thus the data are inconclusive. Testing has shown that the proportion and type of speciated Hg presented to an APCD is not consistent; however, as stated above, the data do indicate that PM controls are reasonably effective where particulate-bound Hg is present. This variation of the proportions of speciated Hg within the flue gas between units provided further explanation for the observed removal characteristics for different units using the same control technology. Further evaluation of Hg speciation indicated that different coal ranks tend to speciate to a predominantly similar proportion of speciated forms of Hg, thus further supporting the rationale for the subcategorization of coal-fired units based on coal rank.

The EPA found, for the reasons indicated above, that although variable, fabric filter and ESP control technologies were reasonable and viable technologies on which to base the MACT floor level of control. The EPA then evaluated performance of the various fabric filter- and ESP-equipped units to determine what criteria would most effectively reflect the performance. The EPA considered using the percent efficiency of the control device, the percent reduction, and outlet concentration as viable criteria to demonstrate performance of the technology. However, the evaluation of these performance criteria proved problematic. The ICR Hg data were based on stack test data for the last control device at each utility unit tested. The emissions were measured in milligrams of Hg per volume of test solution used in the Ontario-Hydro method. Using the duct or stack flue-gas flow volume and the heat input to the unit being tested, the measured quantity of Hg was converted and reported in units of lb/TBtu. In reviewing the data, EPA found that the inlet measurement showed deficiencies due to the flow rate and short duct runs available for testing before the control device, and that these values were suspect as being reliable representations of actual inlet concentrations. The EPA, therefore, determined that evaluation of control device efficiency values based on unreliable inlet concentration data would not be justified. The EPA determined, however, that the outlet concentration data were reliable based on the method used and the fact that only one measurement was needed for the determination of the value. Another option was then to determine Hg reduction efficiency across the system.

This option would also address EPA's desire to promote, and give credit for, coal preparation practices that remove Hg before firing (*i.e.,* coal washing or beneficiation). However, this option requires tracking the Hg concentrations in coal from receipt to stack, and not just before and after the control device(s) and could be difficult to implement. The EPA believes that an emission rate format would allow for the use of precombustion Hg removal processes. As a result, EPA believes that the most credible data element available that quantified performance would be the emission rates as provided in the stack test reports.

The emission limitation for Hg emissions from existing coal-fired units was determined by analyzing the available Hg emissions data in each subcategory. The data were obtained from the ICR noted earlier and included data for Hg emissions, and Hg-in-coal and Cl-in-coal data for 1999. The MACT floor calculations were based on the average performance of the top 12 percent of units in the individual subcategories of bituminous coal, subbituminous coal, lignite coal, coal refuse, and IGCC (coal gas).

The variability of Hg emissions from coal-fired units is significantly influenced by the variability over time in the composition of the coal burned as fuel (*i.e.*, differences in Hg content, Cl content, and heat content of coal). The differing physical and chemical properties of Hg-containing compounds in the flue gas result in significant differences in the feasibility and effectiveness of controls for removing the compounds from flue gas. The effectiveness of control devices at removing Hg depends to a large extent on the species of Hg in the flue gas. As a general matter, all of the control devices currently installed on Utility Units are most effective at removing Hg in the oxidized form (*e.g.*, Hg^{++}). Thus, which Hg species are present in the flue gas impacts the amount of Hg that will be captured by control devices and how much Hg will be released in stack emissions. Importantly, studies have shown that the Cl content of the coal has a significant impact on which Hg compounds are contained in the flue gas. Generally, the higher the Cl content relative to the Hg content, the greater the percentage of oxidized Hg (ionic or Hg^{++}) contained in the flue gas. When combined with other relevant data, such as coal Hg content, the Cl content of coal can thus be used to predict a particular control device's ability to effectively reduce Hg emissions.

The data results from a multi-variable study EPA performed on the ICR data demonstrate the significance of coal Cl content to Hg emissions controllability. The higher the Cl:Hg ratio, the more likely the formation of mercuric chloride (Hg^{++}) that is more readily captured by existing control devices. This Cl:Hg ratio is independent of the coal rank as an indicator of Hg controllability.

In summary, the coal Cl content is one of the primary determinants of which Hg-containing compounds will be present, and in what amounts, in the flue gas of an individual utility unit. The differing physical and chemical properties of Hg-containing compounds in the flue gas result in significant differences in the feasibility and effectiveness of controls for removing the compounds from flue gas.

The EPA determined that the stack tests in the ICR database alone are insufficient to estimate the effect of fuel variability over time on the emissions of the best-performing facilities. The ICR database contains extensive data on variation in coal composition recorded over the course of a year. Therefore, to link fuel composition data to Hg emissions data, EPA developed a methodology using correlation equations to represent the relationship between the fraction of Hg removed and Cl concentration for each of the control configurations used by the best-performing units. The correlation equations provide a mechanism for predicting the performance of each of the control devices installed on floor units when the unit is combusting any of the coals received by that unit during 1999. The steps used to develop these correlation equations are set forth below.

The units in each of the five subcategories were sorted in ascending order of stack-tested Hg emission factor, measured in units of lb/TBtu (as adjusted by a method that normalizes Hg emissions to coal heat content (F-factor Adjustment)). Accordingly, the top performing units of each subcategory were selected for further analysis.

The control configuration of each of the best-performing units (*i.e.*, the floor units) was identified. The Hg removal fraction and test coal Cl concentrations were obtained from the ICR database for each of the units in the database that have one of the identified control configurations. It was necessary to look at all units employing the identified control configurations to ensure that the statistical r^2 values of the subsequently derived correlation equations were sufficiently high to conclude that the correlation equations could accurately predict the Hg removal efficiency of a particular control device in operation on one of the floor units.[6] Finally, a correlation equation was derived for each identified control configuration by fitting a mathematical expression to the Hg removal fractions and corresponding Cl concentrations obtained from the ICR stack test database. The correlation equations thus derived can be applied to any control device for which the Hg control efficiency, when the unit being controlled is burning a coal with an identified Cl:Hg ratio, is known to predict the control efficiency of that device when a coal with a different Cl:Hg ratio is burned.

In selecting the format of the correlation equation, care was taken that the mathematical expression accurately reflected the physical and chemical process by which Cl contributes to the controllability of stack Hg emissions. The correlation equation is based on the assumption that the rate of conversion of Hg to mercuric chloride (an oxidized form) is proportional to the Cl concentration in the coal, irrespective of coal rank. With this expression, the maximum removal fraction is limited to 1, because the exponent term is always nonnegative, regardless of the Cl concentration. This corresponds to the real-world limitation that no more than 100 percent of the Hg in flue gas can be removed (*i.e.*, there cannot be negative Hg emissions). As the coal Cl concentration drops to zero, the Hg removal fraction does not approach zero because some Hg removal is achieved even without reaction with Cl. The purpose of deriving a correlation equation for each control configuration used by the top performing units was to provide a numerical means of predicting the fraction of Hg removed for the best-performing sources over the entire range of fuel variability experienced by each of those sources over the course of a year. Correlation equations were derived for each control configuration, but were only used to predict Hg removal if they

[6] The r^2 measures the strength of the relationship between any two variables in the sense that it provides the proportionate reduction in the sum of squares of vertical deviations obtained using a least squares approach. The largest value r^2 can attain is 1, which occurs when the residual sum of squares is equal to zero (*i.e.*, all the data points lie on the curve), while the smallest value that r^2 may take is 0, which means there is no improvement in predictive power using the independent variable. In our example, the two variables of concern in effecting Hg reductions are the Hg and Cl content of coal. Thus, the closer r^2 comes to 1, the stronger the relationship between these two variables, and reductions in Hg emissions, for any given coal sample; and, on the other hand, the closer r^2 comes to 0, the more likely there is little or no relationship between the two variables, and reductions in Hg emissions, for a given coal sample.

were found to have acceptable explanatory power.

To determine whether the explanatory power of each correlation equation warranted its use on a larger range of ICR coal composition data, each correlation equation was validated against the ICR stack test data. For each of the Cl concentrations in the ICR stack test database for 1999, the Hg removal fraction was calculated by using the correlation equation with parameters selected to give the best fit to the data. A correlation coefficient was then calculated to evaluate the accuracy of the fit.

For each of the best-performing units, unit-specific coal composition data for a one-year period were extracted from the ICR database to find the coal heat content, Hg content and Cl content. For each set of coal composition data from the ICR database, the controlled Hg emissions were calculated by multiplying uncontrolled Hg emissions by (1-Hg removal fraction). For each of the best-performing sources, this process was repeated for each set of measured coal composition values, yielding a range of controlled Hg emission levels for that unit over time.

The test coal composition data from the ICR database (heat and Hg content) was used to calculate the uncontrolled Hg emission level. The Hg removal fraction was calculated in one of the following two ways:

(1) Where the correlation equation was found to have sufficient explanatory power, it was used to estimate the Hg removal fraction based on coal Cl composition data from the ICR data base. This approach accounted for variations in the Hg, Cl, and heat content of fuel.

(2) Where the correlation equation was a poor fit, the Hg removal fraction was based on the average Hg removal fraction observed in the ICR stack tests of that unit. This latter approach yielded a constant removal fraction based upon the source test, and had the effect of reducing the variability of predicted Hg emissions. Under this approach, the measured impact of fuel variability was limited to the effect of variations in Hg and heat content, while variations in Cl concentration were not explicitly considered.

For each of the best-performing units, the calculated controlled Hg emissions, calculated in accordance with the procedures outlined above, were then sorted from smallest to largest to obtain a cumulative frequency distribution (CFD). The 97.5th percentile value of this distribution (*i.e.*, an emission rate that is expected to be exceeded only 2.5 percent of the time) was determined to represent the operation of the unit under conditions reasonably expected to occur at the unit.

It is necessary also to account for inter-unit variability among the top performers. The analysis of within-unit variability considered only the top units in each subcategory. A focus on within-unit variability alone is not expected to capture the full range of emissions variability among the best-performing sources. The EPA accounted for this variability by calculating a 97.5 percent upper confidence level for the mean by use of the student t-statistic.

The EPA calculated the emission limitation for Hg for the subcategories of bituminous-fired, subbituminous-fired, lignite-fired, IGCC, and coal refuse-fired units as follows.

For bituminous-fired units, EPA had data from 32 units. Because this subcategory (*i.e.*, nationwide population) included more than 30 units, EPA determined that the top 12 percent of the units in the subcategory would be composed of 12 percent of the number of units for which EPA had data (*i.e,* 4 units). The EPA determined the top four units from a ranking of units based on their emission rates from the stack test reports. The emission rates from these units ranged from 0.1062 lb/TBtu to 0.1316 lb/TBtu, with an average of 0.118 lb/TBtu. After applying variability as described above and rounding to 2 significant figures, EPA determined the inlet-based emission limitation to be 2.0 lb/TBtu. Using the conversion described elsewhere in this preamble (and based on 32 percent net efficiency), the inlet-based emission limitation of 2.0 lb/TBtu was converted to 21×10^{-6} lb/MWh as the outlet-based emission limitation.

For subbituminous-fired units, EPA had data from 32 units. Because this subcategory (*i.e.*, nationwide population) included more than 30 units, EPA determined that the top 12 percent of the units in the subcategory would be composed of 12 percent of the units for which EPA had test data (*i.e.*, 4 units). The EPA determined the top units from the ranking of the units based on their emission rates from the stack test reports. The emission rates from these units ranged from 0.4606 lb/TBtu to 1.207 lb/TBtu, with an average of 0.738 lb/TBtu. After applying variability as described above and rounding to 2 significant figures, EPA determined the inlet-based emission limitation to be 5.8 lb/TBtu. Using the conversion described elsewhere in this preamble (and based on 32 percent net efficiency), the inlet-based emission limitation of 5.8 lb/TBtu was converted to 61×10^{-6} lb/MWh as the outlet-based emission limitation.

For lignite-fired units, EPA had data from 12 units. Because this subcategory (*i.e.*, nationwide population) consisted of fewer than 30 units, EPA determined that the top performers must include the top 5 units. The emission rates from these units ranged from 3.977 lb/TBtu to 6.902 lb/TBtu, with an average of 5.032 lb/TBtu. After applying variability as described above and rounding to 2 significant figures, EPA determined the inlet-based emission limitation to be 9.2 lb/TBtu. Using the conversion described elsewhere in this preamble (and based on 32 percent net efficiency), the inlet-based emission limitation of 9.2 lb/TBtu was converted to 98×10^{-6} lb/MWh as the outlet-based emission limitation.

For IGCC units, EPA had data on two units. Because this subcategory (*i.e.*, nationwide population) included less than 30 units, EPA determined that all available units would be included and were ranked based on their emission rates from the stack test reports. The emission rates from these units ranged from 5.334 lb/TBtu to 5.471 lb/TBtu, with an average of 5.403 lb/TBtu. The EPA applied the variability factors and, with rounding to two significant figures, determined the IGCC input-based emission limitation to be 19 lb/TBtu. Using the conversion described elsewhere in this preamble (and based on 32 percent net efficiency), the inlet-based emission limitation of 19 lb/TBtu was converted to 200×10^{-6} lb/MWh as the outlet-based emission limitation.

For coal refuse-fired units, EPA had data from two units. Because this subcategory (*i.e.*, nationwide population) included fewer than 30 units, EPA used all units for the calculation based on their emission rates from the stack test reports. The emission rates from these units ranged from 0.0816 lb/TBtu to 0.0936 lb/TBtu, with an average of 0.0876 lb/TBtu. The EPA applied the variability factors as described above and with rounding to two significant digits, determined the input-based emission limitation to be 0.38 lb/TBtu. Using the conversion described elsewhere in this preamble (and based on 32 percent net efficiency), the inlet-based emission limitation of 0.38 lb/TBtu was converted to 4.1×10^{-6} lb/MWh as the outlet-based emission limitation.

The EPA believes that the Hg emission limitations derived above, using the test data adjusted for appropriate variability, provide a reasonable estimate of the actual performance of the MACT floor units under all conditions expected to be encountered over time.

Some have argued that the experience gained from regulation of Municipal

Waste Combustors and Health, Medical and Infectious Waste Incinerators in the early 1990s indicates that coal-fired power plants should be able to achieve 90 percent Hg emission reductions (*see* ''Out of Control and Close to Home: Mercury Pollution from Power Plants.'' Environmental Defense. 2003). The EPA expects that some Utility Units can achieve such high reduction rates, depending on factors such as the Hg and Cl content of different coals, as outlined above. However, there are important technical differences between Utility Units and municipal waste combustors and health, medical and infectious waste incinerators. Consequently, EPA believes 90 percent emission reductions cannot be achieved across all Utility Units in the proposed section 112 time frame. First, the percentage of emissions that is elemental Hg is much larger in coal-fired boilers than in the waste combustors and incinerators (*e.g.*, 50 percent versus 2–20 percent, as stated in EPA's Mercury Study Report to Congress). Second, Hg emissions from the waste combustors and incinerators can be reduced effectively through waste separation techniques, which remove Hg-containing items from the incoming waste stream (*e.g.*, batteries). Application of similar measures at coal-fired Utility Units, such as effective pre-combustion Hg removal, is not widely feasible at this time, though some innovative techniques are under development. Third, the Hg emissions at the waste combustors and incinerators often occur as infrequent, high-concentration ''spikes,'' which are more easily controlled than highly diluted Hg in the flue gas found at coal-fired Utility Units. The technical differences between Utility Units and municipal waste combustors and health, medical and infectious waste incinerators need to be recognized (*see* ''Mercury Emissions from Coal-Fired Power Plants: The Case for Regulatory Action,'' NESCAUM, 2003).

Are there other approaches to addressing variability? The approach selected by EPA for addressing variability is not the only approach that could be appropriate for evaluating emissions from the best-performing units. The Department of Energy (DOE) has conducted a similar analysis to that described above, but with one significant difference. (DOE, 2003.) In calculating a MACT ''floor'' rate, DOE considered that variability at a best-performing unit could be based on assuming that the unit could switch to a coal not previously burned at the unit during the one-year period covered by the ICR, but having the same rank as the coal used at the best-performing unit. Because the alternative coals were of the same rank and not precluded from use by regulation or permit, DOE concluded that the combination of emission algorithms, unit-specific stack tests, and ICR coal data from other units constituted relevant emission estimates under worst conditions at the best-performing units.

The essence of the DOE analysis was to average at a plant level the Hg and Cl contents of all coals, by rank, in the ICR data base. Then, DOE adjusted the performance test results at the lowest emitting units in the ICR data base by assuming that they burn a coal similar to the 97.5th percent worst plant annual average coal. For bituminous coal units, the coal Cl resulted in the greatest variability in emissions. For subbituminous coals, the coal Hg content was more critical than Cl content. The DOE found that most lignite-fired power plants were directly associated with a single mine, and decided that assuming a switch to coals from other mines was not reasonably justified. Therefore, for lignite units, DOE would recommend using the approach presented earlier by EPA. In addition, for bituminous coals, DOE found that many of the lowest Cl bituminous coals are produced in the western U.S. and are unlikely to be used in eastern power plants, where the bulk of bituminous coal is burned. Those western coals were excluded from the variability analysis.

Using this approach, DOE found that an appropriate MACT floor rate for bituminous coal was 2.6 lb/TBtu heat input. The rate for subbituminous coals was 5.4 lb/TBtu heat input. The EPA seeks comment on alternative approaches to addressing source emission variability, such as DOE's. In particular, we ask for comment on the relevance of *Cement Kiln Recycling Coalition* to the DOE approach.

How did EPA address blended coals? The EPA recognizes that many Utility Units burn more than one rank of coal, either at the same time (*i.e.*, blending) or at separate times during a year (*i.e.*, seasonally). Further, EPA is aware that several units burn a supplementary fuel (*e.g.*, petroleum coke, tire-derived fuel (TDF), etc.) in addition to a primary coal fuel. The EPA recognizes this practice and acknowledges the effect that coal blending (or use of supplementary fuels) will have on Hg emissions. Because this rule does not apply to the non-regulated supplementary fuels, the rule does not provide an emission limitation for those fuels. The EPA believes that the most appropriate means to address the blending scenarios is through the compliance demonstration.

The EPA has identified several blending scenarios that might occur in the industry; blending two or more ranks of coal, blending one rank of coal with a supplementary (non-regulated fuel), or blending multiple ranks of coal with a supplementary (non-regulated) fuel.

There are two potential methods for addressing the blending scenarios where two or more ranks of coal are fired. One approach to address blended coal would be to classify a unit based on the predominate coal it burns. For example, if 90 percent of the coal burned for the compliance period were bituminous, the unit would be classified as bituminous and would have to meet the Hg emission limitation for bituminous coal. Although this approach is desirable from a simplicity standpoint, EPA believes that this approach is not equitable nor reflective of actual practice in the industry. Therefore, EPA is proposing a second, potentially more equitable, approach involving development of a weighted Hg emission limit based on the proportion of energy output (in Btu) contributed by each coal rank burned during the compliance period and the coal's subcategory Hg emission limitation. The weighted emission limit would, in effect, be a blended emission limitation based on the Hg emission limitations of the subcategories of the coals burned.

The other scenarios discussed above involve blending a regulated fuel (*e.g.*, coal or coal refuse) with a supplementary, non-regulated fuel (*e.g.*, petroleum coke, TDF, etc.). The application of the same methods would be appropriate for units that burn a regulated fuel with supplementary, non-regulated fuels; however, there would be no adjustment to the Hg emission limitation with regard to the supplementary, non-regulated fuel.

The weighted Hg emission limitation would be developed based on the proportions of energy output (Btu) contributed by only the regulated fuels. For example, if the unit burned bituminous, subbituminous, and petroleum coke during the compliance period, and where 40 percent of the Btu output was attributable to the bituminous, 40 percent to the subbituminous, and 20 percent to the petroleum coke, the blended Hg emission limitation would be based on the bituminous and subbituminous emission limitations in a 50/50 ratio. The compliance calculation would include the energy output (Btu) of all fuels burned (including the supplementary fuel), the emissions

considered would include all Hg emission measured by the CEMS, and the unit would comply with the blended Hg emission limitation. The compliance demonstration outlined in § 63.9990(a)(6) of the proposed rule provides the calculation of the blended Hg emission limitation applicable under this approach.

How did EPA address Ni from oil-fired units? The proposed emission limit for Ni from existing oil-fired units was determined by analyzing the emissions data available. The data were obtained from the Utility RTC which provided information indicating that Ni was the pollutant of concern due to its high level of emissions from oil-fired units and the potential health effects arising from exposure to it. The EPA examined available test data and found that units equipped with ESP units (for PM control) can effectively reduce Ni. The controls currently in use on electric utility oil-fired units to address PM were installed as a result of requirements to address criteria pollutants under other regulations. The data available to EPA indicate that the Ni is present in flue gas streams in varying concentrations, yet mostly in particulate form. The Utility RTC emissions test data support the conclusion that the same control techniques used to control the fly-ash PM will also indiscriminately control Ni and that the effective removal of PM indicates removal of Ni, for a given control device. Therefore, EPA believes that ESP technology represents the MACT floor for Ni for the proposed rule. The EPA has determined that the proposed emission limitation for the oil-fired units should reflect the performance that would be expected over time for a well designed and operated ESP.

The EPA determined the value of the Ni emission limitation by ranking the stack test emission rates for Ni of the 17 units for which EPA had data. The top 12 percent of the units, or 2 units, were controlled by ESP and the range of emission rates was 29.97 to 357.16 with an average of 125.06 lb/TBtu. After applying variability as described above and rounding to 2 significant figures, EPA determined the inlet-based emission limitation to be 210 lb/TBtu. The output-based Ni emission limitation was determined to be 0.002 lb/MWh after conversion using 32 percent net efficiency. The EPA believes that these emission limits are a reasonable estimate of the actual performance of the MACT floor unit in reducing Ni on an ongoing basis.

The Agency is sensitive to the fact that some sources burn fuels containing very little Ni and that compliance with the Ni emission limitation could be burdensome in cases where the potential Ni emissions would be very low. Therefore, EPA is considering an alternative Ni-in-oil emission limit which would be equivalent to the main standard. An existing source would be able to choose to comply with the alternative Ni-in-oil emission limitation instead of the Ni emission limitation (either input- or output-based) to meet the proposed rule. The alternate Ni-in-oil emission limitation would be based on a correlation between the Ni constituent concentration in the oil burned and the expected Ni emissions in the flue gas. Data available to EPA does not provide a consistent correlation methodology for determination of an appropriate Ni constituent level in oil. The EPA is soliciting comment on the usefulness of such an alternative Ni-in-oil limit and the availability of any correlation methodology and data for determining a Ni concentration level in oil that could be shown to be equivalent to the proposed emission limitation.

The EPA solicits comments on these approaches and on others that might present a better method for addressing variability in development of the emission limitations.

How did EPA address dual-fired units? The EPA is aware that an oil-fired unit may fire oil at certain times of the year and natural gas at other times, as well as blends of residual oil and distillate oil. This blending of fuels is conducted for many reasons, most of which are economically driven with regard to the availability of fuels and the price, and may be seasonal in nature. As stated elsewhere in this preamble, EPA considers a unit to be an oil-fired unit if (1) it is equipped to fire oil and/or natural gas, and (2) it fires oil in amounts greater than or equal to 2 percent of its annual fuel consumption. This 2 percent value is intended to represent that amount of oil that a true natural gas-fired unit might use strictly for start-up purposes on an annual basis.

As stated earlier for coal blending, EPA does not intend to address the fuel blending scenarios with specific emission limitations, but rather address the issue during the compliance demonstration.

In the proposed rule, units that burn distillate oil exclusively would be exempt from the requirements of the rule and natural gas-fired units would be excluded from the definition of an affected source. Therefore, the requirements of the proposed rule would apply to units that fire residual oil in any proportion with another oil, and to units that fire residual oil at 98 percent or greater of its annual fuel consumption, where the supplementary fuel is natural gas. The blending scenarios that might occur for oil-fired units include the co-firing of residual oil with distillate oil, and the firing of residual oil and natural gas at different times. The EPA believes that a cutoff of 2 percent fuel oil-firing would separate those units that are ''fundamentally'' natural gas-fired but, for start-up or other operational needs, periodically burn fuel oil.

Under the proposed rule, a unit that burns residual oil exclusively would be required to meet the oil-fired Ni emission limitations. For units that burn exclusively distillate oil, the unit would be exempted from meeting the Ni emission limitation requirement. For units that blend residual oil with distillate oil, the unit would be required to meet the Ni emission limitations in the proposed rule, and would include all Btus or MWh generated from the use of the distillate oil in the compliance demonstration calculation. Likewise, a unit that burns residual oil during certain periods and natural gas during certain periods would include the natural gas-fired contributions (Btu or MWh) in the compliance calculation.

Although EPA has not identified any other supplementary fuels burned in the oil-fired industry, we are aware that such a scenario may exist or might occur in the future. For the purposes of the proposed rule, EPA intends that where any supplementary fuel is co-fired with residual oil, the Btus or MWh contributed by the supplementary fuel be accounted for in the compliance calculation, and that the unit would be required to meet the Ni emission limitation for existing oil-fired units.

The EPA solicits comment on whether the 2 percent breakpoint is a reasonable basis for allowing those units that use oil only for startup purposes to be exempted from regulation under the proposed rule.

6. How Did EPA Consider Beyond-the-Floor Options for Existing Units?

The EPA considered available regulatory options (*i.e.*, technologies or work practices) that were more stringent than the MACT floor level of control for each of the different subcategories. Except for IGCC, we have not identified technologies or work practices that provide a viable basis for establishing standards beyond-the-floor. Described below are the candidate technologies and work practices that we considered in our analyses. We ask for comment on these technologies and other control techniques that could provide

consistently lower levels of emissions of Hg and Ni than those demonstrated by the MACT floor level of control. Additional information on the beyond-the-floor analyses for existing units is available in the document titled, ''Beyond the Floor Analysis for Existing and New Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP'' which can be found in the docket.

Coal-fired units. Conventional PM controls (ESP and fabric filters) generally do not remove the vapor-phase Hg^0 from coal-fired unit emissions. This is because these controls do not capture gaseous pollutants. Two technologies that possibly could be used to further reduce the amount of vapor-phase Hg emitted from utilities are sorbent injection and selective catalytic reduction (SCR).

Sorbent injection. Due to their multiple internal pores and high specific surface area, sorbents have the potential to improve the removal of Hg (mostly through the enhanced capture of elemental Hg; sorbents will also remove Hg^{++}) as well as other gaseous pollutants that are carried with combustion fine particulates in all coal-fired subcategories (except IGCC). The extent of the potential Hg removal is dependent on: (1) Efficient distribution of the sorbent (*e.g.*, activated carbon) in the flue gas; (2) the amount of sorbent needed to achieve a specific level of Hg removal which will vary depending on the fuel being burned; (3) the amount of Cl present in the fuel; and (4) the type of PM control device (*e.g.*, at a given sorbent feed rate, a fabric filter provides more Hg control than an ESP because of the additional adsorption that occurs on the bags of the fabric filter because of the increased gas contact time).

Sorbents can be introduced by two basic methods: by channeling flue gas through a bed of sorbent or by direct sorbent injection. Sorbent bed designs consist of fixed-sorbent filter beds, moving beds, or fluidized sorbent filter beds. With direct sorbent injection, after sorbent is introduced into the flue gas, it adsorbs Hg and other contaminants and is captured downstream in an existing or sorbent-specific PM control device. At this time, the types of sorbent that may be viable for use in sorbent injection include two basic types of activated carbon (AC; regular and impregnated), as well as other carbon (mixed with other sorbents) and non-carbon sorbents.

Activated carbon is a specialized form of carbon produced by pyrolyzing coal or various hard, vegetative materials (*e.g.,* wood) to remove volatile material. The resulting char then undergoes a steam or chemical activation process to produce an AC that contains multiple internal pores and has a very high specific surface area. With this internal pore structure, the AC can adsorb a broad range of contaminants. Some studies have shown good to excellent Hg removal with the injection of AC (particularly on bituminous-fired units); however, other studies have not shown good Hg removal (particularly on subbituminous- and lignite-fired units). The Hg removal performance of AC injection seems to be highly dependent on coal rank and composition (*i.e.,* Hg and Cl content of the coal) and specific utility plant configuration (*e.g.,* sequencing of APCD equipment). Further, little long-term data is available.

Chemically-impregnated AC is AC that has been supplemented with chemicals to improve its Hg removal. The Hg in the flue gas reacts with the chemical that is bound to the AC, and the resulting compound is removed by the PM control device. Typical impregnants for AC are Cl, sulfur, and iodide. Chemically-impregnated AC have shown enhanced Hg removal over regular AC. Chemically-impregnated AC require smaller rates of carbon injection than does regular AC for equivalent Hg removals. The required carbon-to-mercury mass ratio may be reduced by a factor of from 3 to 10 with the chemically-impregnated AC. The cost per mass unit of impregnated AC may, however, be significantly greater than that of unmodified AC.

Other commercially available sorbent materials are Sorbalit™ (a mixture of lime with additives and 3 to 5 percent AC) and Darco FGD (an AC derived from lignite). Zeolites comprise another category of sorbent. There are naturally occurring mineral zeolites, in addition to commercially available synthetic zeolites. Both types contain large surface areas and have a good potential for Hg removal.

Although AC, chemically-impregnated AC, and other sorbents show potential for improving Hg removal by conventional PM and SO_2 controls, this technology is not currently available on a commercial basis and has not been installed, except on a demonstration basis, on any electric utility unit in the U.S. to date. Further, no long-term (*e.g.,* longer than a few days) data are available to indicate the performance of this technology on all representative coal ranks or on a significant number of different power plant configurations. Therefore, we do not believe these technologies provide a viable basis for going beyond-the-floor.

Selective catalytic reduction. Although designed as a NO_X control technology, SCR has been shown in recent emissions testing to have the ability to transform certain species of Hg into other speciated forms that are easier for conventional PM and SO_2 controls to capture. The effect can be seen most prominently when an SCR is installed between the PM control device and a wet FGD control device on a unit that is already controlled by such technologies. The Hg which would (in the absence of the SCR) tend to remain as Hg^0 is oxidized, and this highly soluble Hg^{++} is then removed by the wet FGD. This Hg reduction effect has been observed in limited stack testing on bituminous coal-fired units. Results on subbituminous coal-fired units have not been uniformly successful. To EPA's knowledge, no commercial-scale, lignite-fired, SCR-equipped unit has been tested to date, though it is entirely possible that greater Hg removal would result when applied to a lignite-fired unit. Similarly, SCR has not been tested on all types of coal sources.

The EPA requests comments on whether sorbent injection or SCR should be considered as viable beyond-the-floor options for existing coal-fired units. Our preliminary determination is that sorbent injection has not been sufficiently demonstrated in practice nor have long-term economic considerations been evaluated to allow sorbent injection to be considered viable as a beyond-the-floor option. With regard to the use of SCR, the EPA has inadequate information on which to base a beyond-the-floor standard. The EPA is aware that research continues on ways to improve Hg capture by PM controls and sorbent injection and on the development of novel Hg capture techniques. Therefore, EPA also requests comments on whether other control techniques have been demonstrated to consistently achieve emission levels lower than levels on similar sources achieving the proposed MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs, including retrofit costs.

IGCC units. The EPA believes the best potential way of reducing Hg emissions from existing IGCC units is to remove Hg from the syngas before combustion. An existing industrial IGCC unit has demonstrated a process, using sulfur-impregnated AC carbon beds, that has proven to yield 90 to 95 percent Hg removal from the coal syngas. (Rutkowski, 2002) This technology could potentially be adapted to the

electric utility IGCC units. The EPA believes this to be a potentially viable option for IGCC units.

We considered using sorbent bed technology as beyond-the-floor for existing IGCC units but, because of concerns about the costs involved and because existing IGCC units utilize older technology, have decided not to pursue this option. The EPA is, however, proposing that the use of a sorbent bed to remove Hg from coal gas be considered as the beyond-the-floor option for new IGCC units. The EPA requests comments on whether the use of this or other control techniques have been demonstrated to consistently achieve emission levels that are lower than levels from similar sources achieving the proposed existing MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs, including retrofit costs.

Coal refuse-fired units. All of the 13 coal refuse-fired units existing in 1999 use FBC; 10 of these 13 units inject limestone as a sorbent for SO_2 control, and 4 units are equipped with SCR for NO_X control. The only two coal refuse-fired units on which performance tests were conducted in response to the ICR are the MACT floor facilities for the coal refuse-fired subcategory.

The EPA knows of no technologies that could be used as beyond-the-floor options for coal refuse units. However, the EPA requests comments on whether existing coal refuse-fired units could use any control techniques that have been demonstrated to consistently achieve emission levels that are lower than levels for similar sources achieving the proposed existing MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs, including retrofit costs.

Oil-fired units. The only emission control technology that EPA is aware of to consider as a beyond-the-floor option for existing oil-fired units is fabric filtration. Fabric filters have been shown in pilot-scale testing to be more effective at reducing Ni emissions than an ESP. However, the use of fabric filters on oil-fired units is also known to be problematic due to the prevalence of the ''sticky'' PM emitted from such units which sticks to the fabric and creates a fire safety hazard. No existing oil-fired units are known to employ fabric filters as their PM control. Because of this, EPA does not consider fabric filters to be a viable beyond-the-floor option for oil-fired units.

The EPA requests comments on whether fabric filters should be considered as a beyond-the-floor option for existing oil-fired units. The EPA also requests comments on whether other control techniques have been demonstrated to consistently achieve Ni emission levels that are lower than levels for similar sources achieving the proposed MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs, including retrofit costs.

7. Should EPA Consider Different Subcategories for Coal- and Oil-Fired Utility Units?

Although EPA has proposed subcategorizing coal-fired units into five subcategories (bituminous coal, subbituminous coal, lignite coal, coal refuse, and IGCC), another possible option is to subcategorize coal-fired units into four subcategories (bituminous and subbituminous coals, lignite coal, coal refuse, and IGCC). This second option is claimed by some industry sources to allow greater fuel choice flexibility. Approximately 23 percent of the coal-fired units in 1999 fired a blend of coal ranks or coals and other fuels. The majority of blended coal-fired units in the U.S. combust a blended coal composed of bituminous and subbituminous coal, either through direct blending or through independently combusting each coal at some period during the year. A standard that would subcategorize bituminous and subbituminous together would allow easier emissions permitting and flexibility because most units do not keep the ratio of the coals blended constant.

Although the above subcategorization scheme is not included in this proposal, the EPA specifically requests comments on whether additional or different subcategories should be considered. Comments should include detailed information regarding why a new or different subcategory is appropriate (based on the available data or adequate data submitted with the comment), how EPA should define any additional/different subcategories, how EPA should account for varied or changing fuel mixtures, and how EPA should use the available data to determine the MACT floor for any new or different categories.

8. How Did EPA Determine the Proposed MACT Floor for New Units?

For new sources, the CAA requires that the MACT floor be based on the emission control achieved in practice by the best-controlled similar source, as determined by EPA. The MACT standard is subsequently based on any combination of measures or techniques that are ascertained to have contributed to that level of control (*e.g.,* pollution prevention alternatives, capture and control technologies, operational limitations, work practices) unless a more stringent level of control is required based on the above-the-floor analysis. Because the MACT floor represents the level of reduction in HAP emissions that is actually demonstrated by the best-controlled similar source, EPA may not consider cost and other impacts in determining the floor.

In order to develop a MACT floor for new coal- and oil-fired units, EPA used the same data described above for existing sources. With regard to Hg and Ni emissions from new units, EPA believes that the character and levels of Hg and Ni emitted by new coal- and oil-fired units will be similar to those emitted by existing coal- and oil-fired units because the source of Hg and Ni is primarily related to the fuel. The EPA has no data or information that indicate that this situation will change in the future, particularly because EPA anticipates the use of primarily the same fossil fuel sources for new units as are being used for existing units.

The EPA is aware that the industry has some ability during the designing of new units to choose coal or oil that would minimize emissions of Hg and Ni and recognizes that the MACT standard for new units should, to the extent possible, encourage the industry in that direction. The type, grades, and ranks of coal and grades of oil available for future use in new units will not likely change, and the availability and economics of the fuel choice for these units will likely still be a dominating factor in the design of new units. Future technology may, however, allow for better efficiencies in the units and, potentially, the use of a wider range of fossil fuels for a given locale or region.

The EPA does believe that Hg from coal-fired units and Ni from oil-fired units will remain a concern and that regulation of emissions of Hg and Ni is warranted for new coal- and oil-fired units under the proposed rule.

As was the case for existing units, in developing a MACT strategy for new units, EPA considered several prevention measures as an alternative to the application of Hg and Ni control technology. These measures were the same precombustion techniques evaluated for existing units, which included fuel substitution, process changes, and work practices.

The EPA first considered the feasibility of fuel substitution from

several perspectives: (1) Switching to other fuels used in the same subcategory (*e.g.,* a ''lower'' Hg content bituminous coal); (2) switching to fuels used in another subcategory (*e.g.,* firing bituminous coal instead of lignite coal); or (3) switching to natural gas. The EPA considered several aspects of fuel switching in evaluating these alternatives. The EPA recognizes that an owner/operator, in designing a new unit, would be able to choose a perceived better coal rank (between subcategories) or a perceived better coal seam within a rank (within the subcategory) based on known issues of Hg and other pollutant control and would be able design the new unit to that fuel's characteristics. However, the economics of fuel availability would still be a determining factor as to what fuel was chosen, particularly with regard to new units co-located with existing units.

With regard to a possible EPA requirement for new sources to burn natural gas, EPA believes that availability and economics again would determine whether a source would chose to burn natural gas and that such a requirement would be unduly restrictive given the owner/operator's inability to control access to, or availability of, natural gas. For these reasons, EPA decided that mandated fuel type is not an appropriate criterion for identifying the MACT level of control for new coal-fired units. In any event, we do not believe that we can or should prescribe a given fuel type because of the implications on electricity reliability, energy security, etc.

With regard to process design alternatives and GCP, EPA believes, as discussed elsewhere in this preamble for existing sources, industry has a strong economic incentive to pursue improvement in combustion and plant efficiencies and that the trends in design and technology development will continue in the direction of improvement in efficiencies such that imposition of regulatory incentives based on the existing knowledge base would be not only unnecessary but potentially restrictive. In addition. we do not have the data necessary to establish such a standard.

As with existing units, EPA therefore determined that precombustion techniques were not viable for application in the MACT standard for new coal- or oil-fired units.

Once EPA had determined that pollution prevention alternatives would not be appropriate for the new coal- or oil-fired MACT development, EPA then evaluated the control technology used by the top performing unit (*i.e.,* equipment based), and the level of emissions reductions (*i.e.,* emission limitation based) that the top unit in each subcategory demonstrated.

The EPA used the same data available for existing units which provided an evaluation of the Hg control performance of various emission control technologies that are either currently in use on coal-fired units (designed for pollutants other than Hg) or that could be applied to such units for Hg control. The EPA decided to address Hg for new units using an emission limitation-based approach.

As was discussed in MACT floor development for existing sources, EPA is confident that the data available were obtained from units representative of the industry; however, EPA did believe that some adjustments to the data were justified in light of the variability in test method and in Hg-in-fuel that was discussed previously with regard to existing units. Although it was necessary to address the variability issues, the use of one data set (*i.e.,* the best unit vs. the top units) negated the applicability of the unit-to-unit variability issue. Otherwise, the variability issues were addressed in the same manner as was discussed above for existing units.

The MACT floor for new units is based on the emission control achieved in practice by the best-performing similar source. As noted earlier, EPA believes it reasonable to subcategorize new sources in the same manner as has been done for existing sources. In order to develop an emission limitation for new coal- and oil-fired units, EPA ranked the existing coal- and oil-fired units from lowest emitting to highest within each subcategory based on Hg or Ni emission rates from the stack test data. The EPA then took the numerical performance value from the best-performing unit (or equivalent).

The EPA then applied the potential uncertainty and variability in the emission test reports and worst-case Hg in fuel variability (if applicable) to derive the Hg emission limitation values for new units.

Because test data were provided to EPA based on an input-based format (lb/TBtu), EPA conducted the emission limitation calculations using the input-based format and then converted the input-based format into an output-based format (lb/MWh) according to the approach described elsewhere in this preamble for the proposed rule. The discussion below describes the development of the emission limitation for each subcategory and each regulated pollutant for coal- and oil-fired units.

Mercury from new coal-fired units. The emission limit for Hg emissions from new coal-fired units was determined by analyzing the available Hg emissions data in each subcategory. The data were obtained from the ICR and included data for Hg emissions and Hg- and Cl-in-coal data from all coal-fired units for 1999. The MACT emission limitation calculation was based on the performance of the best similar source in the individual subcategories of bituminous coal, subbituminous coal, lignite coal, coal refuse, and IGCC (coal gas).

This performance value was adjusted for variability by using an approach consisting of a combination of the statistical analysis of the emissions test data and the application of a factor representing the ratio of the Hg-in-coal during the stack testing to the highest Hg-in-coal reported for the unit during 1999 (ICR test). The variability approach used for adjusting the new unit's Hg emissions data was modified to a simplified version of the existing unit's variability factor that reflected the removal of the unit-to-unit variability issue. The worst-case Hg-in-coal issue was addressed in the same manner as the existing units, based on the Hg- and Cl-in-coal data for the individual unit. The EPA chose the same confidence interval (97.5 percent) as was used for existing units, for the reasons discussed in that section.

For bituminous-fired units, the best-controlled unit was controlled with a fabric filter, and the Hg emission factor was 0.132 lb/TBtu. This value was adjusted for variability as described above, converted to the output-based format using the 35 percent efficiency factor, with a resulting output-based Hg emission limitation for new bituminous-fired units of 6.0×10^{-6} lb/MWh.

For subbituminous-fired units, the best-controlled unit was also controlled with a fabric filter, and the Hg emission factor was 0.663 lb/TBtu. This value was adjusted for variability as described above, converted to the output-based format using the 35 percent efficiency factor, with a resulting output-based Hg emission limitation for new subbituminous-fired units of 20×10^{-6} lb/MWh.

For lignite-fired units, the best controlled unit was controlled with an ESP, and the Hg emission factor was 6.902 lb/TBtu. This value was adjusted for variability as described above and converted to the output-based format using the 35 percent efficiency factor, with a resulting output-based Hg emission limitation for new lignite-fired units of 62×10^{-6} lb/MWh.

For IGCC units, the best-controlled unit was uncontrolled, and the Hg emission factor was 5.471 lb/TBtu. This value was adjusted for variability as described above and converted to the output-based format using the 35 percent efficiency factor, with a resulting output-based Hg emission limitation for new IGCC units of 200×10^{-6} lb/MWh. However, EPA believes that a 90 percent reduction in Hg emissions is possible from new IGCC units based on the use of carbon bed technology. Therefore, EPA is proposing an output-based Hg emission limitation for new lignite-fired units of 20×10^{-6} lb/MWh as a possible beyond-the-floor level of control for new IGCC units.

For coal refuse-fired units, the best-controlled unit was controlled with a fabric filter, and the Hg emission factor was 0.094 lb/TBtu. This value was adjusted for variability as described above and converted to the output-based format using the 35 percent efficiency factor, with a resulting output-based Hg emission limitation for new coal refuse-fired units of 1.1×10^{-6} lb/MWh.

The EPA believes that these Hg emission limitations, based on the best-performing unit with associated variability applied, are a reasonable estimate of the actual performance of the MACT floor unit on an ongoing basis.

Blended coals. The EPA recognizes that new Utility Units may still be designed to burn more than one rank of coal, either at the same time (*i.e.,* blending) or at separate times during a period of time (*i.e.,* seasonally). The EPA finds no reason to address blended coals differently for new units than has been proposed for existing units. Therefore, the method of addressing blended coals with regard to the Hg emission limit calculation will remain the same for new units as is proposed for existing units. Further, EPA believes that consistency in the compliance method would be appropriate, because many utility owners/operators will at some point be addressing compliance for both new and existing units at the same facility.

Nickel from new oil-fired units. The proposed emission limit for Ni from existing oil-fired units was determined by analyzing the emissions data available. The data were obtained from the Utility RTC which provided information indicating that Ni was the pollutant of concern due to its high level of emissions from oil-fired units and the potential health effects resulting from exposure to it. The EPA examined available test data and found that ESP-equipped units can effectively reduce Ni. The Ni average concentration from the emission data of the best-controlled oil-fired unit was used to determine the emission limitation for new oil-fired units. The best oil-fired unit Ni emission value from the stack test data was 0.0046 lb/TBtu. This emission factor was then adjusted for uncertainty by applying variability factors as described above for existing units, with a resulting input-based Ni emission limit of 76 lb/TBtu. The EPA then converted the input-based value using the 35 percent net efficiency factor to derive the output-based value for the proposed rule. The resulting proposed Ni emission limitation for new oil-fired units is 0.0007 lb/MWh. The EPA believes that this emission limitation is a reasonable estimate of the actual performance of the MACT floor unit on an ongoing basis.

The EPA is also considering development of an alternative Ni-in-oil limit for new oil-fired units. The EPA solicits comment as to the usefulness of such a limit and any available data or methodology to determine a Ni constituent level in oil that would be equivalent to the proposed Ni emission limitation.

Dual-fired units. The EPA is aware that new oil-fired units may be designed and built to fire a combination of oil grades and/or natural gas, as are existing units. The EPA believes that the reasons for burning natural gas and/or any grade of oil will continue to be based on economics or availability of fuel (*i.e.*, seasonal considerations). Therefore, EPA intends to address new oil-fired units that burn a combination of oil grades and/or natural gas in the same manner as existing units.

The method and rationale for determining the MACT floor for existing and new units is presented in detail in the document titled ''MACT Floor Analysis for Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP'' which can be found in the docket.

9. How Did EPA Consider Beyond-the-Floor for New Units?

Once the MACT floor determinations were done for new units in each subcategory (by fuel type), EPA considered various regulatory options more stringent than the MACT floor level of control (*i.e.*, additional technologies or work practices that could result in lower emissions) for the different subcategories.

Due to the technical complexities of controlling metal HAP emissions from the sources affected by this rule, however, EPA has not been able to determine whether identified potential beyond-the-floor options are available and demonstrated. Consequently, EPA is describing the possible beyond-the-floor options of which the Agency is aware for new units and requests comment on these technologies and other control techniques that have been demonstrated to provide consistently lower levels of emissions than those achieved by the proposed new unit MACT floor level of control.

The following are possible beyond-the-floor control options for new units that EPA is considering for the proposed rule.

Coal-fired units. As is explained for existing coal-fired units elsewhere in this preamble, two technologies that possibly could be used to further reduce the amount of vapor-phase Hg emitted from utilities are sorbent injection and SCR. As explained elsewhere in this preamble, however, sorbent injection is not currently available on a commercial basis and has not been demonstrated on a utility unit operating at full capacity over an extended period of time. As also discussed previously, SCR has not shown the same change-in-speciation effect on Hg emissions on all types of coal sources.

The EPA requests comments on whether sorbent injection or SCR should be considered as a beyond-the-floor option for new coal-fired units and whether these units could use any other control techniques that have been demonstrated to consistently achieve emission levels that are lower than those from similar sources achieving the proposed MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs.

IGCC units. Because of their design, IGCC units have no external APCD controls. Therefore, as is explained for existing IGCC units elsewhere in this preamble, the best potential way of improving Hg removal from IGCC units is to remove the Hg from the syngas before combustion. Based on published information regarding the industrial IGCC unit noted earlier, EPA believes that a 90 percent reduction in Hg emissions is possible from new IGCC units based on the use of carbon bed technology. Therefore, EPA is proposing this 90 percent Hg reduction as a beyond-the-floor level for new IGCC units.

The EPA requests comment on whether such use of a sorbent bed to remove Hg from coal syngas is an appropriate beyond-the-floor option. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs.

Coal refuse-fired units. Because existing units utilizing 100 percent coal refuse, all of which utilize FBC technology, have demonstrated the best Hg control of any emission-tested electric utility unit in the industry, EPA requests comments on whether there are any additional control techniques that have been demonstrated and can be applied to refuse coal-fired units to consistently achieve emission levels that are lower than those of similar sources achieving the proposed new MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs.

Oil-fired units. There has not been a new oil-fired unit constructed in the U.S. since 1981. If a new oil-fired unit is constructed, the only technology that might offer emissions control better than the proposed new unit MACT limits is the use of fabric filtration, which, as is discussed for existing sources elsewhere in this preamble, EPA does not consider to be a viable control option for oil-fired units.

The EPA requests comments on whether the use of fabric filters should be considered as a beyond-the-floor option for new oil-fired units and whether these or other control techniques could be used to consistently achieve emission levels that are lower than those from similar sources achieving the proposed new MACT floor level of control. Comments should include information on emissions, emissions reductions, reliability, current demonstrated applications, and costs.

Additional information on the beyond-the-floor analyses for new units is available in the document titled, ''Beyond the Floor Analysis for Existing and New Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP'' which can be found in the docket.

10. How Did EPA Select the Proposed Testing and Monitoring Requirements?

The CAA requires EPA to develop regulations that ensure initial and continuous compliance. Testing and monitoring requirements allow EPA to determine whether an affected source is operating in compliance with an applicable emission limitation/standard. This section discusses how EPA selected the proposed testing and monitoring requirements used to determine compliance with the Hg emission limits for coal-fired units and the Ni emission limits for oil-fired units that are specified in the proposed rule.

Mercury testing and monitoring requirements. The proposed rule would establish Hg emission limits for coal-fired units. The format selected for these Hg emission limits is a 12-month rolling average Hg emission level expressed in units of lb/TBtu or lb/MWh. Therefore, appropriate testing or monitoring requirements for determining the amount of Hg emitted from an affected unit throughout the compliance averaging period must be included in the rule.

The most direct means of demonstrating compliance with an emission limit is by the use of a CEMS that measures the pollutant of concern. The EPA considers other testing or monitoring options when acceptable CEMS are not available for the intended application or when the impacts of including such CEMS requirements in the proposed rule are considered by EPA to be unreasonable. In determining whether to require the use of other testing or monitoring options in lieu of CEMS, it is often necessary for EPA to balance more reasonable costs against the quality or accuracy of the actual emissions data collected.

There are several approaches to Hg monitoring that EPA has identified for possible use in this rule to determine compliance with the proposed Hg emission limits. One option is to use a CEMS that combines both automated sampling and analytical functions in a single system to provide continuous, real-time Hg emission data. Mercury CEMS are currently available from several manufacturers. These Hg CEMS are similar to most other types of instruments used for continuous monitoring of pollutants from combustion processes, in that the combustion gas sample is first extracted from the stack and then transferred to an analyzer for analysis. In general, the Hg CEMS now available can be distinguished by the Hg measurement detection principle used (*e.g.*, atomic adsorption, atomic fluorescence, x-ray fluorescence). Capital costs for a Hg CEMS are currently estimated to range from approximately $95,000 to $135,000, depending on the manufacturer and model selected. The annual costs to operate and maintain a Hg CEMS are estimated to range from $45,000 to $65,000, again depending on the manufacturer and model selected.

A second option is to use a long-term sampling method that collects a cumulative Hg sample by continuously passing a low-flow sample stream of the combustion process flue gas through a Hg trapping medium (*e.g.*, an activated carbon tube). This sampling tube is then periodically removed (*e.g.*, after a day or up to 1 month) and replaced with a tube filled with fresh trapping medium. The removed sampling tube is then sent to a laboratory where the trapping medium is analyzed for its Hg content. This method, like using a Hg CEMS, is capable of providing data on the Hg emissions from a combustion process on a continuous basis, but unlike a Hg CEMS, the data are not reported on a real-time basis. Using the long-term sampling method, the Hg collected in the sampling tube is integrated over a much longer sampling period (*i.e.*, 1 to 7 days for the AC tube versus less than 15 minutes for the CEMS). The capital cost for a gas metering system and Hg trapping medium is estimated to be approximately $18,000. The annual costs for periodic sampling tube replacement and for the laboratory Hg analysis range from approximately $65,000 to $125,000 depending upon quality assurance and quality control (QA/QC) requirements and frequency of sample tube replacement.

Finally, a third monitoring option is to use one of the manual stack test methods available for measuring Hg emissions from combustion processes on an intermittent basis. The existing voluntary consensus stack test method ASTM Method D6784–02 (commonly known as the Ontario-Hydro method) is currently the method of choice for measuring Hg species in the flue gas from Utility Units. Another method for measuring total (*i.e.*, not speciated) Hg is EPA Reference Method 29. This method involves a technician extracting a representative flue gas sample over a relatively short period of time (*e.g.*, a few hours) using a sampling train consisting of a nozzle and probe, a filter to collect particulate matter, and a liquid solution and/or reagent to capture gas-phase Hg. After sampling, the filter and sorption media are prepared and analyzed for Hg in a laboratory. These test methods could be applied to a Hg monitoring program at electric utility plants by performing a manual stack test using ASTM Method D6784–02 or EPA Reference Method 29 at some specified periodic interval throughout the compliance averaging period (*e.g.*, perform a stack test daily, weekly, biweekly, monthly). The cost to conduct a single ASTM Method D6784–02 typically ranges from $15,000 to $17,000 depending on site conditions. Annual costs will depend on the frequency with which the stack test is required to be performed during the compliance averaging period. For example, if the test is required once per week, the total annual cost would be as much as $780,000 (52 tests in a 12-month period at $15,000 per test).

The EPA evaluated each of the above Hg monitoring options with respect to

its suitability for the measurement of the Hg emission data needed for determining compliance with the 12-month rolling average Hg emission limit. The EPA rejected from further consideration the third option, intermittent monitoring using manual stack test methods. Use of this monitoring approach would place significantly higher labor requirements and monitoring costs on facility owners/operators than the other two options in order to perform an adequate number of source tests throughout the compliance averaging period to demonstrate with reasonable confidence that the applicable Hg emission limit value was being achieved.

Both of the remaining two options would provide the necessary data to calculate the total Hg emissions from an affected source for each 12-month compliance averaging period. While the CEMS would provide these data on a real-time basis, EPA concluded that having real-time data is not mandatory for determining compliance with an emission limit based on a 12-month rolling average. Total Hg emissions from an affected source by month are needed to compute the rolling 12-month average Hg emission value. With regular scheduled replacement and timely analysis of sampling tubes, total monthly Hg emissions can readily be obtained using the long-term sampling method.

The EPA then compared the costs of applying the Hg CEMS and long-term monitoring options to Utility Units. While the CEMS have significantly higher capital costs, the automated analyses directly by the instrument eliminates the need and cost for separate analyses of the collected sampling tubes in a laboratory required by the long-term sampling method. Overall, EPA determined that the total costs of using either monitoring method to determine compliance would be similar for a given site. Selection of which monitoring method should be used at the site will depend on site-specific conditions and owner/operator preferences. Because both monitoring methods will collect the Hg emission data necessary to determine compliance with the proposed Hg emission limit and the costs of either option are reasonable, EPA decided to allow the owner/operator flexibility under the proposed rule to choose to use either Hg CEMS or long-term sampling monitoring as best suits their site conditions and preferences.

An owner/operator electing to use a CEMS to comply with the rule would be allowed to use any CEMS that meets the requirements in ''Performance Specification 12A, Specifications and Test Procedures for Total Vapor-phase Mercury Continuous Monitoring Systems in Stationary Sources'' (PS–12A). This performance specification is proposed as part of this rulemaking and we request comment on continuous monitoring of Hg emissions according to the requirements in the proposed performance specification.

Those owners/operators electing to use long-term Hg monitoring would be required to follow the requirements in Method 324, ''Determination of Vapor Phase Flue Gas Mercury Emissions from Stationary Sources Using Dry Sorbent Trap Sampling'' when it is promulgated. Method 324 is proposed as part of this rulemaking to be added to 40 CFR part 63, appendix A. We request comments on the requirements in proposed Method 324 for Hg measurement using long-term sampling. The owner/operator would use the procedures outlined in § 63.10009 of the proposed rule to convert the concentration output from a CEMS or Method 324 to an emission rate format in lb/TBtu or lb/MWh.

Continuous compliance requirements are required under every NESHAP so that EPA can determine whether an affected source remains in compliance with the applicable emission limitation/standard following the initial compliance determination. In the case of the proposed Utility NESHAP, the format for the Hg emission limit is a 12-month rolling average limit. The same monitoring requirements used to establish initial compliance of an affected electric utility unit with the applicable Hg emission limit at the end of the first 12-month period following the facility's compliance date serve to demonstrate continuous compliance with the Hg emission limit with the computation of each new 12-month rolling average value each month thereafter. Thus, no additional continuous compliance Hg monitoring requirements beyond those previously discussed are required for the proposed rule.

The EPA is concerned about monitoring costs for Utility Units with low Hg emissions rates, and does not desire to adopt a monitoring scheme where the costs are disproportionate to the costs of compliance with the MACT emissions limitations. For these units (*e.g.*, those emitting under 25 pounds per year) the EPA may consider reduced monitoring frequencies and lower cost monitoring requirements, since the need for accuracy is reduced for such units. For example, the EPA is concerned about the merits of requiring an expenditure of $100,000 per year to monitor releases when the costs of substantive compliance is far less. The Agency requests comments and related data upon which to establish an alternate reporting scheme.

Nickel testing and monitoring requirements. The proposed rule would establish Ni emission limits for oil-fired units. The EPA selected a different format for the Ni emission limits than is proposed for the Hg emission limits. The Ni emission limits are maximum allowable emission limits not to be exceeded, expressed in lb/TBtu or lb/MWh.

The EPA selected the proposed testing requirements to determine compliance with the Ni emission limits under the NESHAP to be consistent with existing procedures used for the electric utility industry. Method 29 in appendix A to 40 CFR part 60 is an EPA reference test method that has been developed and validated for the measurement of Ni emissions from stationary sources. For sampling and analysis of the gas stream, the following EPA reference methods would be used with Method 29: Method 1 to select the sampling port location and the number of traverse points; Method 2 to measure the volumetric flow rate; Method 3 for gas analysis; and Method 4 to determine stack gas moisture. Method 19 specifies the procedure for collecting the necessary fuel data to be used with the Method 29 Ni measurements from the source test to compute the Ni emission rate expressed in units of lb/TBtu.

As an alternative under the proposed rule, an owner/operator of an existing source could choose to comply with the applicable Ni emission limit expressed in lb/MWh. The owner/operator would use the procedures outlined in § 63.10009 of the proposed rule to convert the concentration output of Method 29 to the output-based emission rate format.

To address the need for continuous compliance requirements for the proposed Ni emission limits, EPA considered the availability and feasibility of a number of Ni monitoring options ranging from direct monitoring of Ni emissions, to process parameter monitoring, to control device parameter monitoring. Monitors for continuously measuring Ni emissions have not been demonstrated in the U.S. for the purpose of determining compliance. Therefore, EPA did not consider further the use of continuous monitors for Ni for the proposed rule.

Another option used in other NESHAP for demonstrating continuous compliance is to monitor appropriate process and/or control equipment operating parameters. These parameters are established during the initial, and

any subsequent, stack test. Process parameters were not selected as indicators for Ni emissions from Utility Units because a direct correlation does not exist between combustion or electricity production parameters and Ni emission rates from a given unit.

Monitoring of PM control device operating parameters is used in other NESHAP established for combustion processes and other source categories that include PM emission limits. The EPA decided to also use this continuous monitoring approach to demonstrate continuous compliance with the applicable Ni emission limits set forth in the proposed rule. The selected operating parameters for the PM control device used by oil-fired Utility Units (*e.g.*, ESP) are reliable indicators of control device performance. The EPA believes that reasonable assurance of compliance with the emission limits proposed for this NESHAP can be achieved through appropriate monitoring and inspection of the operation of the APCD that have been demonstrated by an initial performance test to achieve the applicable Ni emission limits under the rule.

Compliance calculations. For cogeneration units, steam is also generated for process use. The energy content of this process steam must also be considered in determining compliance with the output-based standard. This consideration is accomplished by taking the net efficiency of a cogeneration unit into account. Under a Federal Energy Regulatory Commission regulation, the efficiency of cogeneration units is determined from the useful power output plus one-half the useful thermal output (18 CFR 292.205). To account for the process steam energy contribution to net plant output, a 50-percent credit of the process steam heat is necessary. Such a credit would, EPA believes, provide an incentive for cogeneration.

Therefore, owners/operators of cogeneration units subject to the proposed rule would need to monitor the portion of their net plant output that is process steam so that they can take the 50-percent credit of the energy portion of their process steam net output. For example, a cogeneration unit subject to the rule measures its net electrical output over a compliance period, as 30,000 MWh. During the same period the unit burns coal that provides 750 billion Btu input to its furnace/boiler, and emits 0.2 lb Hg. Using equivalents found in 40 CFR 60 for electric utilities (*i.e.*, 250 million Btu/hr input to a boiler is equivalent to 73 MWe input to the boiler; 73 MWe input to the boiler is equivalent to 25 MWe output from the boiler; therefore, 250 million Btu input to the boiler is equivalent to 25 MWe output from the boiler) the 50-percent credit could be found as follows. The net output calculation would be 750 billion Btu × (25 MWe output/250 million Btu/hr input) = 75,000 MWh equivalent electrical output from the boiler over the compliance period. Of this amount, 30,000 MWh was produced as electricity sent to the grid, leaving 45,000 MWh as the energy converted to steam for process use. Half of this amount is 22,500 MWh. The unit's Hg CEM records a total of 0.2 lb Hg over the same compliance period. The adjusted Hg emission rate is then: 0.2 lb Hg/(30,000 MWh + 22,500 MWh) = 3.8×10^{-6} lb Hg/MWh.

11. How Did EPA Determine Compliance Dates for the Proposed Rule?

Section 112(i) of the CAA specifies the dates by which affected sources must comply with the emission standards. New or reconstructed units must be in compliance with the proposed rule immediately upon startup or [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**], whichever is later, except that if the final rule is more stringent than the proposal, a new source that commences construction before the final rule is promulgated may comply with the proposed rule for 3 years before complying with the final rule. Existing sources must be in compliance with the final rule 3 years after the effective date of the final rule. Existing sources may seek a permit granting an additional one year to comply if such time is necessary for the installation of controls.

We anticipate that a substantial number of sources would have to install control technologies to meet the limits of the proposed standard, if the CAA section 112 MACT rule is finalized. We also believe that such construction could be constrained by the potential impacts on electricity reliability, delays in obtaining permits, and other factors (including potential labor and equipment shortages). Thus, we anticipate that a substantial number of units will seek the 1-year extension which could unduly burden State and local permitting authorities. Therefore, EPA is soliciting comment on whether a 1-year extension should be granted for facilities required to install controls in order to comply with the proposed CAA section 112 MACT rule, should it be finalized.

12. How Did EPA Select the Proposed Recordkeeping and Reporting Requirements?

Under section 114(a) of the CAA, EPA may require owners/operators of affected sources subject to a NESHAP to maintain records as well as prepare and submit notifications and reports to the EPA. In addition, section 504(a) of the CAA mandates that sources required to obtain a title V permit submit a report setting forth the results of any required monitoring no less often than every 6 months. The general recordkeeping, notification, and reporting requirements for all NESHAP are specified in 40 CFR 63.9 and 40 CFR 63.10 of the General Provisions, if incorporated into the proposed rule. The recordkeeping, notification, and reporting requirements for the proposed rule were selected to include all of the applicable records, notifications, and reports specified by the General Provisions requirements. Additional requirements were included in the proposed rule that are necessary to ensure that a given affected source is complying with the emission limits from the correct subcategory.

The proposed rule would also require that the owner/operator keep monthly records for each affected source listing the type of fuel burned, the total fuel usage, and the fuel heating value. Additional recordkeeping would be required for those owners/operators electing to comply with a fuel blending emission limit. The owner/operator would be required to maintain records of all compliance calculations and supporting information.

13. Will EPA Allow for Facility-Wide Averaging?

The proposed rule contains provisions allowing the owner/operator of a coal-fired affected unit to demonstrate compliance through the averaging of Hg emissions from multiple affected units located at a common, contiguous facility site. Consistent with EPA policy on regulatory flexibility, this provision is intended to provide a facility with the benefit of operational flexibility while still meeting the proposed emission limitations and achieving the required emissions reductions. This averaging provision effectively allows the owner/operator to average the emissions from multiple (two or more) coal-fired affected units and comply with one applicable facility-wide emission limitation.

The proposed rule would require that any coal-fired affected unit included in the facility's averaging regime be a regulated unit under the proposed rule (*i.e.*, coal-fired Utility Units only, and

not combined with sources regulated by other rules, such as IB units).

The averaging provision may be applied to meet the proposed emission limitations for Hg from coal-fired units. An important aspect of this provision is that the emissions measurements for the averaging calculations are taken after the last control device. Affected units that share a common control device are inherently averaged by the standard compliance calculations provided in § 63.10009 of the proposed rule. It is the intention of EPA to provide additional flexibility to average all coal-fired units at one facility into one averaged emission limit. In accordance with that intent, the initial and continuous compliance demonstration under this averaging provision would be to determine the emission rate applicable to all affected units (which may be individual or blended) according to requirements under § 63.10009 and then use those limits to calculate a limit for the emissions averaging group according to § 63.99991 of the proposed rule.

The owner/operator would be required to limit Hg emissions from the group of all affected units being averaged to an overall Hg emission limit (emissions-averaged emission limit, AvEL) during each 12-month compliance period. The owner/operator would be required to use the AvEL determined in accordance with § 63.99991 of the proposed rule throughout the 12-month compliance period and may not switch between compliance with individual subcategory emission limits and an AvEL. The format of the AvEL (lb/MWh or lb/TBtu) would also be required to remain constant throughout the 12-month compliance period. The owner/operator would keep all records as required by sections 63.10031 and 63.10032 of the proposed rule. The owner/operator would be required to submit information on the affected units which comprise each AvEL group for which the owner/operator used a calculated AvEL; the emission limits (including format) that would be averaged (*i.e.*, Hg); the units that will be averaged together; and the calculation of the AvEL with which the averaged units will comply. The owner/operator may implement emissions averaging at any time after the effective date with submission of the averaging plan. The owner/operator must revise the plan to change an emissions averaging group. The owner/operator must certify in each semiannual compliance report that the AvEL group of affected units was in compliance with the emission limitation.

The EPA solicits comment on the emissions averaging provision, particularly on the usefulness of the provision and its specific applicability requirements.

III. Proposed Revision of Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units

A. What Action Is EPA Taking Today?

Today, EPA proposes revising the regulatory finding that it published on December 20, 2000 (65 FR 79825) pursuant to section 112(n)(1)(A) of the CAA. The EPA is proposing such a revision based on its review of the December 2000 finding, the Utility RTC underlying that finding, and the provisions of the CAA. For the reasons discussed below, EPA proposes to find that regulation of coal- and oil-fired Utility Units under section 112 is not ''appropriate and necessary'' within the meaning of section 112(n)(1)(A). As a consequence, EPA also proposes to delete such units from the CAA section 112(c) list. The EPA does not propose revising its December 2000 conclusion with regard to HAP emissions from natural-gas fired electric utility steam, however, as it continues to believe that regulation of such units is not appropriate and necessary.

What was EPA's December 2000 ''necessary'' finding? Was EPA's December 2000 ''necessary'' finding overbroad? As noted above, in December 2000, EPA concluded that it was

> ''necessary to regulate HAP emissions from coal- and oil-fired electric utility steam generating units under section 112 of the CAA because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from such emissions.'' (65 FR 79830)

Upon further review of the record and the December 2000 notice, EPA believes that this finding is over-broad in two respects.

First, the ''necessary'' finding might be interpreted to suggest that all HAP emissions from coal- and oil-fired Utility Units pose ''serious public health * * * hazards.'' (65 FR 79830) Upon further review of the record, EPA recognizes that it could not reasonably have reached such a conclusion based on the record before it in December 2000. That record supports only a finding that emissions of Hg and Ni warrant regulation. Nothing in the Study or the information EPA obtained following that study even arguably supports the proposition that EPA should address HAP emissions from Utility Units other than emissions of Hg and Ni.

Second, the ''necessary'' finding states that emissions of HAP from Utility Units result in ''serious * * * *environmental hazards.*'' (*See* 65 FR 79830.) (emphasis added.) After re-examining the record, EPA recognizes that this conclusion also cannot be supported by the record. As an initial matter, the Utility RTC, consistent with CAA section 112(n)(1)(A), focused solely on hazards to public health, not the environment. In fact, the Study expressly states that the ecological impacts associated with HAP from Utility Units were not examined because such impacts were beyond the scope of the Study mandated by CAA section 112(n)(1)(A)) (ES at 27). The only information in the record concerning the effects of HAP on the environment was for Hg, and that information was obtained after completion of the Utility RTC. Thus, given the record before the Agency in December 2000, the most EPA could have intended to state in the December 2000 ''necessary'' finding is it is necessary to regulate Hg from coal-fired Utility Units and Ni from oil-fired Utility Units because the implementation of other requirements under the CAA will not adequately address the serious public health hazards arising from such emissions or the environmental hazards associated with Hg. Moreover, as explained below, EPA has recently re-analyzed this ''necessary'' determination and the premise underlying that determination.

Does other CAA authority exist to address emissions of Hg and Ni from coal- and oil-fired Utility Units? The EPA continues to believe that emissions of Hg from coal-fired Utility Units and emissions of Ni from oil-fired units pose hazards to public health, that coal-fired Utility Units are the largest domestic source of Hg emissions, and that oil-fired units are the primary source of Ni emissions. These findings support a determination that it is appropriate to regulate emissions of Hg and Ni from Utility Units.

We have had an opportunity to re-assess the ''necessary'' finding made in December 2000. Today, we propose to revise that finding because, after examining the scope of available authorities under the CAA, we have determined that there is, in fact, another viable statutory mechanism that would adequately address Hg and Ni emissions from coal- and oil-fired Utility Units. That authority is CAA section 111.

The scope of existing authorities under the CAA. The EPA interprets the language of CAA section 112(n)(1)(A)

and the limited legislative history relating to that provision as indicating Congress' intent that Utility Units be regulated under section 112 only if the other authorities of the CAA, once implemented, would not adequately address those HAP emissions from Utility Units that warrant regulation. This interpretation is supported by the first sentence of section 112(n)(1)(A), which requires EPA to conduct a study that focuses on the hazards to public health that would exist following implementation of the other authorities of the CAA. It is further evidenced by the final sentence of section 112(n)(1)(A), which calls for regulation of Utility Units under section 112 only if, based on the results of the Study, EPA determines that it is both appropriate and necessary to regulate such units. Finally, the remarks made by Congressman Oxley, a member of the conference committee, concerning the Conference Report on the CAA Amendments of 1990, confirm that Congress sought to regulate under section 112 ''only those units [Utility Units] that * * * (the Administrator) determines—after taking into account compliance with all other provisions of the act * * *—have been demonstrated to cause a significant threat of serious adverse effects on public health.'' [7] (136 Cong. Rec. E3670, 3671 & H12911, 12934 (daily ed. Nov. 2, 1990) (Statement of Congressman Oxley)

Based on the foregoing, EPA believes if we make a determination under section 112(n)(1)(A) that it is appropriate to regulate Utility Units, we are not compelled to regulate Utility Units under section 112 if other authorities in the CAA exist to adequately address health hazards that occur as a result of HAP emissions. The EPA believes that this is a reasonable interpretation of the term ''necessary'' in CAA section 112(n)(1)(A), and that it is wholly consistent with its interpretation of the term in December 2000. (*See* 65 FR 79830. ''It is necessary to regulate * * * under section 112 of the CAA because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from such emissions * * *'')

Since December 2000, EPA has had the opportunity to conduct a more thorough review of the available authorities under the CAA. Based on that review, EPA has identified a provision of the CAA that it believes can be employed to adequately address the hazards to public health resulting from Hg and Ni emissions from Utility Units. That provision is CAA section 111, which authorizes EPA to develop standards of performance for new and existing sources of air pollutants that cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.

The EPA based its ''necessary'' finding in December 2000 solely on its belief, at the time, that there were no other authorities under the CAA that would adequately address Hg and Ni emissions from coal- and oil-fired Utility Units. Now that we have re-examined the scope of existing authorities under the CAA and identified a viable statutory mechanism other than section 112, we propose to revise the December 2000 ''necessary'' finding accordingly. We specifically propose to find that regulation of coal- and oil-fired Utility Units under section 112 is *not* necessary because CAA section 111, once implemented, would adequately address the public health hazards posed by Utility Unit emissions of Hg and Ni.[8]

We further believe that CAA section 111, once implemented, would adequately address any environmental effects associated with Hg emissions from Utility Units, as documented in the record. We recognize that the plain language of CAA section 112(n)(1)(A) requires an examination solely of hazards to public health associated with HAP emissions, not of hazards to the environment. Nevertheless, in this case, and given that the December 2000 finding addresses both the health and environmental effects of Hg, we believe that our section 111 proposal would adequately address both of those effects.

Regulation under CAA section 111. Overview. The two relevant provisions of section 111 are section 111(b), which applies to new sources, and section 111(d), which applies to existing sources. As explained below, EPA believes that these provisions authorize the establishment of standards of performance both for Hg emissions from new and existing coal-fired Utility Units and for Ni emissions from new and existing oil-fired units, and that such standards, once finalized, would adequately address the health hazards resulting from Hg and Ni emissions. Indeed, through this notice, EPA proposes such standards of performance. We explain below why the proposed standards adequately address any public health hazards resulting from Hg and Ni emissions from Utility Units and the environmental effects associated with Hg emissions.

Regulation under section 111(b). Pursuant to CAA section 111(b)(1)(A), EPA has established a list of stationary source categories. The EPA is to include a source category on the section 111(b) list if it determines that such category causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. Section 111(b) further requires EPA to establish federal standards of performance for new sources within each listed source category.

The EPA included Utility Units on the section 111(b) list of stationary sources in 1979. (44 FR 33580; June 11, 1979.) The EPA has also previously promulgated federal standards of performance for such units for pollutants like NO_X, PM, and SO_2. (*See* subpart Da of 40 CFR part 60.)

Nothing in section 111(b) precludes EPA from promulgating additional standards of performance for other pollutants emitted from new Utility Units. Indeed, where, as here, EPA has determined that emissions of Hg and Ni from coal- and oil-fired Utility Units warrant regulation, the establishment of Federal standards of performance under section 111(b) is appropriate.

Moreover, nothing in CAA section 111 or section 112 indicates that Congress sought to regulate HAP exclusively under section 112. Rather, the language of sections 112(c)(6), 112(d)(7) and 112(n)(1)(A) supports the conclusion that HAP emissions could be regulated under other provisions of the CAA. There is nothing in the legislative history to suggest that Congress sought to preclude EPA from regulating HAP under other sections of the Act. We, therefore, believe that CAA section 111(b), as amended in 1990, constitutes a viable and appropriate statutory authority by which to regulate Hg emissions from new coal-fired Utility Units and Ni emissions from new oil-fired units.

[7] Congressman Oxley further noted that regulation under CAA section 112 should be imposed ''only if warranted by the scientific evidence.'' 136 Cong. Rec. E3670, 3671 & H12911, 12934 (daily ed. No. 2, 1990) (Statement of Congressman Oxley).

[8] The EPA examined various provisions of the CAA, including section 111, prior to issuing its December 2000 regulatory finding. (Utility RTC.) At that time, we did not believe that any other provisions of the CAA would adequately address the health hazards of concern associated with Hg and Ni emissions. Now, after re-analyzing the provisions of the CAA, we recognize that CAA section 111 is a viable statutory mechanism that would adequately address Hg and Ni emissions from coal- and oil-fired units. The premise underlying our December 2000 ''necessary'' finding, therefore, lacks foundation. Nothing precludes EPA from revisiting its December 2000 ''necessary'' determination, particularly, where, as here, the basis for that determination involved the scope of existing statutory provisions and those provisions have not changed substantively since 1990.

Regulation under section 111(d). CAA section 111(d), unlike section 111(b), specifically references CAA section 112. The import of that reference is not clear, however, because Public Law 101–549, which is the 1990 amendments to the CAA, contains two different and conflicting amendments to section 111(d). To understand this conflict, it is useful to start with the language of section 111(d) as contained in the 1977 Amendments to the CAA.

In 1977, section 111(d)(1) read as follows:

> The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) or 7412(b)(1)(A) of this title, but (ii) to which a standard of performance under this section would apply if such existing source were a new source. * * *

This language provides that standards of performance should not be established under section 111(d) with respect to any pollutants that are listed as hazardous air pollutants under section 112(b)(1)(A) of the 1977 CAA.

In the 1990 Amendments to the CAA, two different and conflicting amendments to section 111(d) were enacted. Presumably, Congress did not realize that it had passed two different amendments to the same statutory provision. The first amendment, which is the House amendment, is contained in section 108(g) of Public Law 101–549. That section amends section 111(d)(1)(A)(i) of the 1977 CAA by striking the words ''or 112(b)(1)(A)'' from the 1977 CAA and inserting in its place the following phrase: ''or emitted from a source category which is regulated under section 112.'' The second amendment to section 111(d), which is the Senate amendment, is labeled a ''conforming amendment'' and is set forth in section 302 of Public Law 101–549. That section amends CAA section 111(d)(1) of the 1977 CAA by striking the reference to ''112(b)(1)(A)'' and inserting in its place ''112(b).''

These two amendments are reflected in parentheses in the Statutes at Large as follows:

> The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) (or emitted from a source category which is regulated under section 112) (or 112(b)), but (ii) to which a standard of performance under this section would apply if such existing source were a new source. * * *

EPA recognizes that the United States Code does not contain the parenthetical reference to the Senate amendment in section 302 of Public Law 101–549; the codifier's notes to this section state that the Senate amendment ''could not be executed'' because of the other amendment to section 111(d) contained in the same Act. The United States Code does not control here, however. The Statutes at Large constitute the legal evidence of the laws, where, as here, title 42 of the United States Code, which contains the CAA, has not been enacted into positive law. See 1 U.S.C. 204(a); *United States* v. *Welden,* 377 U.S. 95, 98 n.4 (1964); *Washington-Dulles Transportation Ltd.* v. *Metropolitan Washington Airports Auth.,* 263 F.3d 371, 378 (4th Cir. 2001).

A literal reading of the House amendment, as contained in the Statutes at Large, is that a standard of performance under CAA section 111(d) cannot be established for any air pollutant that is emitted from a source category regulated under section 112. Under this reading, EPA could not regulate, under CAA section 111(d), HAP *and non-HAP* emissions that are emitted from a source category regulated under section 112. A literal reading of the Senate amendment is that a standard of performance under section 111(d) cannot be established for any HAP that is listed in section 112(b)(1), regardless of what categories of sources of that pollutant are regulated under section 112. The House and Senate amendments conflict in that they provide different standards as to the scope of EPA's authority to regulate under section 111(d).

Over the years, EPA has identified other conflicting provisions of the CAA. See, *e.g., Citizens to Save Spencer County* v. *EPA,* 600 F.2d 844 (D.C. Cir. 1979). Consistent with principles of statutory construction, the Agency has always sought to harmonize such conflicting provisions, where possible, and to adopt a reading that gives some effect to both provisions. The first step in this process involves an evaluation of what Congress intended by each amendment. This step is difficult here because of the absence of legislative history directly addressing the amendments. For that reason, we focus on the plain language of the amendments.

The Senate language reflects the Senate's intent to retain the pre-1990 approach of precluding regulation under CAA section 111(d) for any HAP that is listed under section 112(b). The Senate's intent is further demonstrated by the fact that the amendment itself it labeled a ''conforming amendment,'' which is generally a non-substantive amendment. By contrast, the House amendment was not a conforming amendment. Rather, the House changed the focus of CAA section 111(d) and sought to preclude only regulation of pollutants emitted from a source category that is actually regulated under section 112. One reasonable interpretation is that the House amendment reflects a desire to change the pre-1990 approach and to expand EPA's authority as to the scope of pollutants that could be regulated under section 111(d). One possible reason for this change is that the House did not want to preclude EPA from regulating under section 111(d) those pollutants emitted from source categories which were not actually being regulated under section 112. Such a reading of the House language would authorize EPA to regulate under section 111(d) existing area sources which EPA determined did not meet the statutory criterion set forth in section 112(c)(3), as well as existing Utility Units.

One way to harmonize the Senate and House amendments is to interpret them as follows: Where a source category is being regulated under section 112, a section 111(d) standard of performance cannot be established to address any HAP listed under 112(b) that may be emitted from that particular source category. Thus, if EPA is regulating source category X under section 112, section 111(d) could not be used to regulate HAP emissions from that particular source category.

We believe that this is a reasonable interpretation as it gives some effect to both amendments. First, it gives effect to the Senate's desire to focus on HAP listed under section 112(b), rather than applying the section 111(d) exclusion to non-HAP emitted from a source category regulated under section 112, which a literal reading of the House amendment would do. Second, it gives effect to the House's apparent desire to increase the scope of EPA's authority under section 111(d) and to avoid duplicative regulation of HAP for a particular source category. We recognize that our proposed reconciliation of the amendments does not give full effect to the House's language, because a literal reading of the House language would mean that EPA could not regulate both HAP and non-HAP from a source category regulated under section 112. Such a reading would be inconsistent with the general thrust of the 1990

amendments, which, on balance, reflects Congress's desire to require EPA to regulate more substances, not to eliminate EPA's ability to regulate large categories of pollutants like non-HAP. Furthermore, EPA has historically regulated non-HAP under section 111(d), even where those non-HAP were emitted from a source category actually regulated under section 112. See, *e.g.,* 40 CFR 62 1100 (California State Plan for Control of Fluoride Emissions from Existing Facilities at Phosphate Fertilizer Plants). We do not believe that Congress sought to eliminate regulation for a large category of sources in the 1990 Amendments and our proposed interpretation avoids this result.

Finally, we believe that the proper inquiry for assessing whether to revise the December 2000 ''necessary'' finding is whether CAA section 111(d) constituted a viable statutory authority by which to address Hg and Ni emissions from existing coal- and oil-fired Utility Units as of 1998, the date on which EPA completed the Utility RTC. The answer, we believe, is yes. At that time, Utility Units were not listed under section 112, which consistent with our proposed interpretation of the conflicting amendments would allow us to regulate HAP from existing sources of such units under CAA section 111(d). The EPA, therefore, believes that it has the authority, and that it had the authority in 1998 when it completed the Utility RTC, to regulate Hg emissions from existing coal-fired Utility Units and Ni emissions from existing oil-fired units pursuant to section 111(d).

Adequacy of regulation under section 111. Adequacy of regulatory methods. The EPA proposes to conclude that section 111 offers adequate regulatory authority to control Hg and Ni emissions from both existing and new coal- and oil-fired Utility Units. For existing sources, subsection (d) of section 111 authorizes EPA to promulgate ''standards of performance'' that States must include in SIP-like plans applicable to those sources. The term ''standard of performance'' is defined in section 111(a)(1) as—

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[9]

The EPA believes that the gravamen of this definition is the phrase, ''best system of emission reduction.'' While the parenthetical following this phrase obligates EPA to consider the factors specified in that parenthetical, the term ''best system'' is not defined, and implicitly accords broad discretion to the Administrator, which includes the demonstration of such systems. The term ''system'' implies a broad set of controls, and the term ''best'' confers upon the Administrator the authority to promulgate regulations requiring controls that he considers superior. Moreover, except that the parenthetical phrase in the definition mandates consideration of certain factors, the definition provides no other explicit constraints in determining the ''best system.'' Therefore, EPA believes that in developing the ''best system of emission reduction,'' the Administrator must consider cost, non-air quality health and environmental factors, as well as energy requirements; and that he is authorized to consider, at his discretion, human health and environmental impacts, air quality impacts, timing and feasibility of control factors, and other factors.

This broad authority conferred on the Administrator means that section 111 constitutes an adequate mechanism for regulating Hg emissions from coal-fired Utility Units, and Ni from oil-fired units. Because the Administrator may consider a broad range of factors in developing standards of performance under section 111, the Administrator has the authority to develop control levels to address the emissions of Hg and Ni that warrant regulation.

Specifically, as described elsewhere in this notice, EPA is proposing today standards of performance for regulating Hg and Ni emissions from certain sources. In the case of Ni, EPA is proposing emission rate requirements to address emissions from oil-fired Utility Units. The basis for these standards of performance is discussed elsewhere in today's notice.

In the case of Hg, EPA is proposing a ''cap-and-trade'' program for emissions of Hg from existing Utility Units. Mercury emissions, on a nationwide basis would, in effect, be capped at a specified level. This cap assures permanent reductions in Hg emissions, which an emissions rate control requirement cannot, in-and-of-itself, assure. States would be allocated specified amounts of Hg allowances—that is authorizations to emit a unit of Hg—which the States would then allocate to their Utility Units. The Utility Units would be permitted to emit Hg up to the amount of their allowances. The trading feature of this program would allow Utility Units to purchase or sell allowances, and adjust their emissions accordingly.

The basis for the 2010 and 2018 caps is discussed elsewhere in today's notice. Moreover, the authorization to trade allows implementation of the emissions cap in the most cost-effective manner. Thus, the cap provides health protection by limiting overall emissions, but in a cost-effective manner.

The EPA recognizes, however, that the overall cap level may not eliminate the risk of unacceptable adverse health effects of Hg emissions. Moreover, a cap-and-trade program raises the possibility that any particular utility may opt to purchase allowances, instead of implementing controls, and that this may result in continued Hg emissions at the previous, uncontrolled levels from that Utility Unit. These emissions may have adverse health impacts within the local area. The EPA recognized this issue in its initial 112(n) finding, when it stated:

> There is considerable interest in an approach to mercury regulation for power plants that would incorporate economic incentives such as emissions trading. Such an approach can reduce the cost of pollution controls by allowing for least-cost solutions among a universe of facilities that face different control costs. Trading also can allow for a greater level of control overall because it offers the opportunity for greater efficiency in achieving control. The EPA, however, recognizes and shares concerns about the local impacts of mercury emissions and any regulatory scheme for mercury that incorporates trading or other approaches that involve economic incentives must be constructed in a way that assures that communities near the sources of emissions are adequately protected. Thus, in developing a standard for utilities, the EPA should consider the legal potential for, and the economic effects of, incorporating a trading regime under section 112 in a manner that protects local populations.

(Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units, FR 65 at 79830 and 65 FR 79831).

To assure that the overall cap level, and the pattern of Hg emissions resulting from the trading program, will be adequately protective, EPA proposes today to couple this program with an evaluation of whether Hg emissions remaining after compliance with the cap-and-trade requirements would cause unacceptable adverse health effects. That is, after implementation of the control requirements by 2010 and by 2018, EPA will evaluate the emission levels, attendant health risks, and

[9] The term, ''standard of performance'' is also defined in section 302(l), although there may be uncertainty about whether that defintion applies to the term as used under section 111. For purposes of this discussion, the section 302(l) defintion is not material.

available control mechanisms and determine whether the actual reductions achieved under this program significantly differ from the outcome predicted by our current analysis. The EPA retains the authority to revise its conclusions as to what constitutes the ''best system'' of emissions reductions for existing sources, and, therefore, to revise the standard of performance, to require additional reductions or controls to address such risks, based on information that would justify selection of a tighter regulatory regime.

Similarly, EPA intends to evaluate whether, following implementation of the controls on Ni emissions from existing oil-fired units, adverse health effects might remain from Ni emissions. As described above, EPA retains authority under section 111(d) to promulgate additional requirements on Ni emissions to address those health effects.

The EPA believes that these overall standards of performance for existing Utility Unit sources of Hg and Ni coupled with authority to evaluate remaining health risks and conduct further rulemaking, adequately address all health effects from Hg emissions that warrant regulation from existing coal-fired Utility Units and Ni emissions from existing oil-fired units as well as the environmental effects of Hg.

As to new sources, section 111(b)(1)(B) authorizes EPA to promulgate ''standards of performance'' directly regulating new sources. The section 111(a)(1) definition of ''standard of performance'' applies to these regulations, and thereby authorizes EPA to consider the same range of factors described above, including, for example, human health and environmental factors as well as technological and feasibility factors. Upon consideration of these factors, EPA proposes a technology-based set of controls for Hg emissions from new coal-fired Utility Units and Ni emissions from new oil-fired units. The basis for these controls is discussed elsewhere in today's notice. Further, section 111(b) provides adequate authority for EPA (i) to evaluate whether, following compliance with the new source standards, remaining Hg and/or Ni emissions result in unacceptable adverse health impacts; and, if so, (ii) to revise the standards of performance to include additional restrictions for those emissions. As a result, for new sources of both Hg and Ni emissions, as in the case of existing sources, section 111 provides regulatory authority that will adequately address all adverse health (and environmental) effects of concern.

Time for implementation. Why does regulation under section 111 adequately address the hazards of concern to public health associated with Hg and Ni emissions? This action is one part of a broader effort to issue a coordinated set of emissions limitations for the power sector. Today's rule would establish a mechanism by which Hg emissions from new and existing Utility Units would be capped at specified, nation-wide levels. A first phase cap would become effective in 2010 and a second phase cap in 2018. Facilities would demonstrate compliance with the standard by holding one ''allowance'' for each ounce of Hg emitted in any given year. Allowances would be readily transferrable among all covered facilities. We believe that such a ''cap and trade'' approach to limiting Hg emissions is the most cost effective way to achieve the reductions in Hg emissions from the power sector that are needed to adequately protect human health and the environment.

The added benefit of this approach is that it dovetails well with the SO_2 and NO_X IAQR published elsewhere in today's **Federal Register**. This rule would establish a broadly-applicable cap and trade program that would significantly limit SO_2 and NO_X emissions from the power sector. The advantage of regulating Hg at the same time and using the same mechanism as SO_2 and NO_X is that significant Hg emissions reductions can and will be achieved by the air pollution controls designed and installed to reduce SO_2 and NO_X. In other words, Hg is reduced as a ''co-benefit'' of controlling SO_2 and NO_X. Thus, the coordinated regulation of Hg, SO_2, and NO_X allows Hg reductions to be achieved in a particularly efficient and cost effective manner.

In theory, the ''co-benefit'' argument could work in both directions: controlling Hg also controls SO_2 and NO_X; controlling SO_2 and NO_X also controls Hg. In deciding how regulatory deadlines influence how investments in controls are sequenced, it makes much more sense to lead with SO_2 and NO_X controls, which are well established, than to lead with Hg controls, which are only at the beginning stages of commercialization. Overly ambitious Hg mandates in the near-term could actually hamper innovation toward more effective and less costly technologies. The quantified health benefits of NO_X and SO_2 are also larger and more certain.

The cap and trade approach to regulating Hg emissions offers certain other advantages over the unit-by-unit or facility-by-facility approach that we have traditionally employed under section 112. For example, a cap and trade system establishes fixed emissions caps that cannot be exceeded, even when existing plants are expanded and new plants are constructed. Thus, the cap provides absolute certainty with regard to national emissions. In contrast, a section 112 rule would limit the emissions of individual units or facilities, but would not limit overall emissions to the environment from the sector.

Another advantage of concurrently regulating Hg and SO_2 is derived from the fact that companies will have the opportunity under the SO_2 cap to generate extra allowances by achieving early reductions. For example, the first phase SO_2 cap under the transport rule becomes effective in 2010. Prior to that year, companies have an incentive to achieve greater SO_2 reductions than needed to meet the current Acid Rain cap because the excess allowances they generate can be ''banked'' and either later sold on the market or used to demonstrate compliance in 2010 and beyond at the facility that generated the excess allowances. In either case, there will be earlier health and environmental benefits because reductions are achieved sooner than they otherwise would be. These benefits extend to Hg emissions because, as explained above, we expect companies to meet the Hg cap by way of the controls they install for SO_2 and NO_X. Consequently, the incentive to achieve early reductions for SO_2 effectively assures early reductions for Hg.

Several additional technical and policy considerations strongly favor a cap-and-trade system. The objective of Hg control, as we understand it today, is not advanced as effectively under the prescriptive traditional MACT approach under section 112(d) for the regulation of HAP. The MACT approach calls for two phases of regulation: the first based on the concept of ''maximum achievable control technology''; the second, to occur 8 years later, based on a ''residual health-risk determination.'' The second phase itself involves a complex, two-step framework: one step to determine a ''safe'' or ''acceptable risk'' level, considering only public health factors, and the second to set an emission standard that provides an ''ample margin of safety'' to protect public health, considering relevant factors in addition to health, such as costs, economic impacts, technical feasibility, uncertainties and other factors.

First, a cap-and-trade approach sets a specific limit or cap on allowable emissions. Under a traditional section 112(d) MACT approach, standards are

based on rates of emissions per unit of input or of production, for example, pounds per million Btu. Variations in production or differences in input mix will result in fluctuations in Hg emissions. Thus, with shifts in coal use and with growth in the economy, Hg emissions would likely substantially exceed the overall emission level achieved when the MACT limits are initially met.

Second, a trading approach is better suited to stimulating development and adoption of new technologies. A cap-and-trade system provides a market incentive for the development and use of cost-effective technology to reduce Hg emissions. A MACT approach provides no such market incentive, so plants do not have an incentive to reduce emissions below the required level. Additionally, the ability to bank unused allowances for future use leads to early reductions of Hg emissions. A trading approach is forward-looking in its assessment of technology, in that it provides a continuous incentive for firms to innovate and develop more cost-effective technologies to reduce Hg emissions.

The traditional section 112(d) MACT approach is designed to promote the use of proven control technologies by requiring all sources in a category to achieve the degree of emission control already accomplished by the average of the best 12 percent of sources in the category. However, such a MACT approach will not stimulate innovation in Hg control technology as well as a cap-and-trade approach because it does not reward reductions beyond the required levels.

Indeed, a traditional 112(d) MACT approach even could inhibit innovation. Section 112(d) does provide legal authority to go ''beyond-the-floor'' to require control strategies more stringent than the MACT floor, but the science, engineering and economics of Hg control have not progressed enough to support the technical determination that would be needed to support a section 112(d) standard that goes beyond the MACT floor. Once MACT-level controls are installed, there is little incentive for firms to develop even more effective technologies. In addition, the MACT deadline is so tight (2007 with only 1 year of possible extension) that affected firms would be unlikely to risk both capital and non-compliance in order to use more innovative approaches to Hg control.

Moreover, a trading approach could spur the development of cost-effective break-through technologies to control national and local Hg emissions. Such innovations would allow the U.S. to play a leadership role in the reduction of global Hg emissions as well. This is a crucial advantage of a trading approach to ultimately help remedy the problems posed by Hg emissions.

Third, from a capital planning perspective, a trading approach permits utilities to make a much more rational investment in emissions control than a traditional MACT approach. We now understand that utility investments in reducing criteria air pollutants (particulate matter, sulfur dioxide and oxides of nitrogen) provide a ''co-benefit'' for Hg control because some forms of Hg (especially those that are deposited nearest plants) are controlled by the same technologies used to control criteria pollutants. The exact size of this co-benefit is not known. In any event, given the likelihood of co-benefits, it makes good economic sense for utilities to coordinate control of criteria air pollutants—especially those needed to achieve the new air quality standards for fine particulate matter and ozone—with their capital investments aimed at reducing Hg emissions. The statutory deadlines for a Hg MACT rule do not permit this rational sequence of investments.

Thus, the Agency has carefully considered sections 112(d), 111, and 112(n) to determine which is more appropriate for application to Hg emissions from coal-fired Utility Units. The scientific, engineering, economic, and environmental considerations all weigh heavily in favor of a trading-based approach.

B. Is It Appropriate and Necessary To Regulate Coal- and Oil-Fired Utility Units Under Section 112 Based Solely on Emissions of Non-Hg and Non-Ni HAP?

In light of our revised interpretation of the scope of existing authority under the CAA, we have re-examined the results of the Utility RTC, focusing on the non-Hg and non-Ni HAP emissions from coal- and oil-fired Utility Units. The Study indicates that there are no non-Hg or non-Ni HAP emissions from Utility Units that warrant regulation.

We do recognize that in December 2000, we stated that arsenic and a few other metals, such as chromium, Ni and cadmium, were of potential concern for carcinogenic effects (65 FR 79827). We continue to believe, as stated above, that the record supports a distinction between the treatment of Ni emissions from oil-fired Utility Units and the emissions of other non-Hg metallic HAP. Such a distinction is warranted based on the relative magnitude of Ni that is emitted from oil-fired utility units on an annual basis and the scope and number of adverse health effects associated with such emissions. Thus, although we recognize that uncertainties do exist with regard to the data and information we have obtained to date for non-Hg metallic HAP, including Ni, we believe that the nature of the uncertainties associated with the non-Hg, non-Ni metallic HAP are so great that regulation of such pollutants is not appropriate at this time since those pollutants do not pose a hazard to public health that warrants regulation. The EPA does intend, however, to continue to study these pollutants in the future. The EPA also intends to continue to study dioxins, HCl, and HF in the future, but, at this time, the Study and the information EPA has obtained since the Study reveal no public health hazards reasonably anticipated to occur as a result of these HAP emissions from Utility Units such that they warrant regulation.[10]

Therefore, we believe that emissions of non-Hg and non-Ni HAP emissions from coal- and oil-fired Utility Units do not warrant regulation. We recognize that we based our appropriateness finding in December 2000, in part, on the existence of available control options that would reduce HAP emissions, including Hg, from Utility Units. *See* 65 FR 79830. The focus on available technologies was, however, a subsidiary rationale and one that was included only after we had determined that emissions of particular HAP from coal- and oil-fired Utility Units posed significant hazards to public health and the environment and that those hazards could only be addressed under CAA section 112. *See* 65 FR 79830.

As discussed above, we believe that any health effects resulting from Hg and Ni emissions from Utility Units can and will be addressed adequately pursuant to CAA section 111. Thus, while control strategies may exist to control the remaining HAP emitted from coal- and oil-fired Utility Units (*i.e.*, HAP other than Hg and Ni), we do not believe that it is appropriate to regulate such HAP under section 112 where we have not determined that emissions of such HAP from Utility Units pose health hazards that warrant regulation. This conclusion is consistent with CAA section 112(n)(1)(A), in which Congress called for EPA to focus on the health effects of

[10] As noted above, after the December 2000 finding, EPA conducted additional modeling that confirmed the Utility RTC's conclusion that acid gas HAP, such as HCl, HF, and Cl, pose no hazards to public health that warrant regulation. Furthermore, since December 2000, EPA has not obtained any new information that would cause it to modify its conclusion concerning the lack of health effects that warrant regulation associated with HAP other than Hg and Ni.

HAP from Utility Units following imposition of the other requirements of the CAA.

Moreover, even if in the future EPA finds that HAP emissions from Utility Units other than Hg and Ni emissions warrant regulation, EPA believes that CAA section 111 could be used to adequately address those hazards. Thus, EPA proposes to find that it is not only inappropriate to regulate coal- and oil-fired Utility Units under section 112 for HAP emissions other than Hg and Ni, but that it is not necessary to do so.

C. What Effect Does Today's Proposal Have on the December 2000 Decision To List Coal- and Oil-Fired Utility Units Under Section 112(c)?

In CAA section 112, Congress established a framework by which source categories could be listed, and once listed, emission standards developed for the listed source categories. The criteria and basis for listing a source category under section 112 differ depending on the sources at issue. (*See* generally CAA section 112(c) (discussing major and area sources).) In particular, for Utility Units, it only would be possible for EPA to list Utility Units under section 112(c) if it first made the section 112(n)(1)(A) finding that it was both appropriate and necessary to regulate such units under section 112, after EPA reviewed the results of its section 112(n)(1)(A) study concerning health effects and alternative control strategies.

In its December 2000 notice EPA took this additional step and after finding it was appropriate and necessary to regulate Utility Units under section 112, went on to list coal- and oil-fired Utility Units under section 112(c)(65 FR 79831).

As explained above, EPA has conducted a thorough re-analysis of the provisions of the CAA and determined that CAA section 111 is a viable statutory mechanism that would adequately address Hg and Ni emissions from coal- and oil-fired Utility Units. Therefore, EPA believes that the premise underlying its December 2000 ''necessary'' finding, that no other authority exists under the CAA to adequately address the public health hazards associated with Hg and Ni emissions, lacks foundation. The EPA also believes that it is not appropriate to regulate HAP other than Hg and Ni under section 112 because the Utility RTC reveals that there are no health hazards that warrant regulation associated with such HAP. Moreover, even if in the future EPA finds that there are HAP emissions (other than Hg and Ni) from Utility Units that pose hazards to public health and warrant regulation, EPA believes that CAA section 111 would adequately address those hazards and, therefore, that regulation of such units under section 112 would not be necessary. For all of these reasons, EPA now believes that its initial decision to list coal- and oil-fired Utility Units under section 112(c) in December 2000 was without proper foundation. The EPA, therefore, proposes to modify the section 112(c) list to delete coal- and oil-fired Utility Units as a source category. In light of EPA's interpretation and proposed use of its existing authority under the CAA and, in particular, CAA section 111, we propose to conclude that the statutory listing criteria were not met in December 2000.

The EPAs proposed action here is wholly consistent with its historical interpretation of CAA section 112(c)(9), which is that the de-listing criteria in section 112(c)(9) apply only where the original listing of a source category was consistent with the statutory listing criteria. The failure to fully recognize the scope of existing statutory authority in December 2000, is analogous to those situations where EPA has listed a source category under section 112(c)(1), and later determined that it lacked a factual predicate for such listing and, therefore, delisted the source category without following the criteria of section 112(c)(9). The EPA has done this on several occasions. For example, in 1992, EPA listed asphalt concrete manufacturers as a major source category [11] under section 112(c)(1), and then in 2002, delisted that category without following the statutory criteria in section 112(c)(9). The EPA did so because it determined that the initial criteria for listing had not been met since the sources in the asphalt concrete manufacturing category did not emit or have the potential to emit sufficient tons of hazardous air pollutants annually to satisfy the statutory definition of ''major source.'' *See* 67 FR 6521, 6522 (February 12, 2002); see also 63 FR 7155, 7157 (February 12, 1998); 61 FR 28197, 28200 (June 4, 1996).

[11] Under the statute, a ''major source'' is any stationary source or group of stationary sources at a single location and under common control that emits or has the potential to emit 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP.

IV. Proposed Standards of Performance for Mercury and Nickel From New Stationary Sources and Emission Guidelines for Control of Mercury and Nickel From Existing Sources: Electric Utility Steam Generating Units

A. Background Information

1. What Is the Statutory Authority for The Proposed Section 111 Rulemaking?

Section 111(b) of the CAA requires EPA to promulgate standards of performance for emissions of air pollutants from new stationary sources. These standards are typically referred to as NSPS. Section 111(d) requires the EPA to prescribe regulations that establish a procedure by which each State shall submit plans which establish standards of performance for existing sources for air pollutants for which air quality criteria have not been set but for which NSPS have been established.

2. What Criteria Are Used in the Development of NSPS?

Section 111(a)(1) of the CAA requires that standards of performance reflect the

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

The reader is referred to our interpretation of standard of performance set forth above.

B. Proposed New Standards and Guidelines

1. What Source Category Is Affected by the Proposed Rulemaking?

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

2. What Pollutants Are Covered by the Proposed Rulemaking?

The proposed rule would add Hg and Ni to the list of pollutants covered under subpart Da by establishing emission limits for new sources and guidelines for existing sources. New sources (and existing subpart Da facilities), however, remain subject to the applicable existing subpart Da emission limits for NO_X, SO_2, and PM. See 40 CFR part 60, subpart Da, Standards of Performance for Electric

Utility Steam Generating Units for which Construction is Commenced after September 18, 1978.

3. What Are the Affected Sources?

Only those coal- and oil-fired Utility Units for which construction, modification, or reconstruction is commenced after January 30, 2004 would be affected by the proposed rule. Coal- and oil-fired Utility Units existing at the time of this proposal would be affected facilities for purposes of the proposed section 111(d) guidelines described in this notice.

4. What Emission Limits Must I Meet?

The following standards of performance for Hg are being proposed in today's notice for new coal-fired subpart Da units:

Bituminous units: 0.00075 nanograms per joule (ng/J) (0.0060 lb/gigawatt-hour (GWh));

Subbituminous units: 0.0025 ng/J (0.020 lb/GWh);

Lignite units: 0.0078 ng/J (0.062 lb/GWh);

Waste coal units: 0.00087 ng/J (0.0011 lb/GWh);

IGCC units: 0.0025 ng/J (0.020 lb/GWh).

The following standard of performance for Ni is being proposed for new oil-fired subpart Da units:

Ni: 0.010 (ng/J) (0.0008 lb/MWh).

All of these standards are based on gross energy output.

Compliance with the proposed standard of performance for Hg would be on a 12-month rolling average basis, as explained in section B.5 below. This compliance period is appropriate given the nature of the health hazard presented by Hg (*see* section B.5 below). Compliance with the proposed standard of performance for Ni would be on a continuous basis.

5. What Are the Testing and Initial Compliance Requirements?

New or reconstructed units must be in compliance with the applicable rule requirements upon initial startup or by the effective date of the final rule, whichever is later. The effective date is the date on which the final rule is published in the **Federal Register**.

Prior to the compliance date, the owner/operator would be required to prepare a unit-specific monitoring plan and submit the plan to the Administrator for approval. The proposed rule would require that the plan address certain aspects with regard to the monitoring system; installation, performance and equipment specifications; performance evaluations; operation and maintenance procedures; quality assurance techniques; and recordkeeping and reporting procedures. Beginning on the compliance date, the owner/operator would be required to comply with the plan requirements for each monitoring system.

Mercury emission limits. Compliance with the proposed standard of performance for Hg would be determined based on a rolling 12-month average calculation. The Hg emissions are determined by continuously collecting Hg emission data from each affected unit by installing and operating a CEMS or an appropriate long-term method that can collect an uninterrupted, continuous sample of the Hg in the flue gases emitted from the unit. The proposed rule would allow the owner/operator to use any CEMS that meets requirements in Performance Specification 12A (PS–12A), ''Specifications and Test Procedures for Total Vapor-phase Mercury Continuous Monitoring Systems in Stationary Sources.'' An owner/operator electing to use long-term Hg monitoring would be required to comply using the new EPA Method 324, ''Determination of Vapor Phase Flue Gas Mercury Emissions from Stationary Sources Using Dry Sorbent Trap Sampling.'' Performance Specification 12A and Test Method 324 are proposed as part of this rulemaking.

For new cogeneration units, steam is also generated for process use. The energy content of this process steam must also be considered in determining compliance with the output-based standard. Therefore, the owner/operator of a new cogeneration unit would be required to calculate emission rates based on electrical output to the grid plus half the equivalent electrical output energy in the unit's process steam. The procedure for determining these Hg emission rates is included in section B.4 of the proposed rule.

The owner/operator of a new coal-fired unit that burns a blend of fuels would develop a unit-specific Hg emission limitation and the unit Hg emission rate for the portion of the compliance period that the unit burned the blend of fuels. The procedure for determining these emission limitations is outlined in section B.4 of the proposed rule.

Nickel emission limits. Compliance with the applicable proposed standard of performance for Ni would be determined by performance tests conducted according to the requirements in 40 CFR 60.8 and 40 CFR 60.11 of the NSPS General Provisions and the requirements in the proposed rule. The proposed rule would require EPA Method 29 in appendix A to 40 CFR part 60 to be used for the measurement of Ni emissions in the flue gas. With Method 29, Method 1 would be used to select the sampling port location and the number of traverse points; Method 2 would be used to measure the volumetric flow rate; Method 3 would be used for gas analysis; and Method 4 would be used to determine stack gas moisture. Method 19 would be used to convert the Method 29 Ni measurements to an emission rate expressed in units of pounds per trillion British thermal units (lb/TBtu) if complying with an input-based standard.

The proposed rule would require the owner/operator to establish limits for control device operating parameters based on the actual values measured during each performance test. The proposed rule specifies the parameters to be monitored for the types of emission control systems commonly used in the industry. The owner/operator would be required to submit a monitoring plan identifying the operating parameters to be monitored for any control device used that is not specified in the proposed rule.

An initial performance test to demonstrate compliance with each applicable Ni emission limit would be required no later than 180 days after initial startup or 180 days after publication of the final rule, whichever is later, for a new or reconstructed unit.

The owner/operator of a new cogeneration unit would have to account for the process steam portion of their emissions in the same manner for Ni emissions as they did for Hg emissions. The owner/operator of a cogeneration unit would be required to calculate the Ni emission rate based on electrical output to the grid plus half the equivalent electrical output energy in the unit's process steam. The procedure for determining these Ni emission rates are given in § 60.46a of the proposed rule.

6. What Are the Continuous Compliance Requirements?

To demonstrate continuous compliance with the applicable emission limits under the proposed rule, the owner/operator would be required to perform continuous Hg emission monitoring for coal-fired units and continuous monitoring of appropriate operating parameters for the ESP used to comply with the Ni limits for oil-fired units. In addition, an annual performance test will be required for demonstrating compliance with the proposed standard of performance for Ni for oil-fired units. The annual performance test would be conducted in

the same manner as the initial compliance demonstration.

7. What Are the Notification, Recordkeeping, and Reporting Requirements?

The proposed rule would require the owner/operator to keep records and file reports consistent with the notification, recordkeeping, and reporting requirements of the General Provisions of 40 CFR part 60, subpart A. Records required under the proposed rule would be kept for 5 years, with the 2 most recent years being on the facility premises. These records would include copies of all Hg emission monitoring data, coal usage, MWh generated, and heating value data required for compliance calculations; reports that have to be submitted to the responsible authority; control equipment inspection records; and monitoring data from control devices demonstrating that emission limitations are being maintained.

Two basic types of reports would be required: initial notifications and periodic reports. The owner/operator would be required to submit notifications described in the General Provisions (40 CFR part 60, subpart A), which include initial notification of applicability, notifications of performance tests, and notification of compliance status. For oil-fired units, if you at any time during the reporting period comply with an applicable emissions limit by switching fuel (in other than emergency situations), the proposed rule would also require that you notify EPA in writing at least 30 days prior to using a fuel other than distillate oil. In emergency situations, such notification must be within 30 days. As required by the General Provisions, the owner/operator would be required to submit a report of performance test results; develop and implement a written startup, shutdown, and malfunction plan and report semi-annually any events in which the plan was not followed; and submit semi-annual excess emissions reports of any deviations when any monitored parameters fell outside the range of values established during the performance test.

C. Rationale for the Proposed Subpart Da Standards

1. What Is the Rationale for the Proposed Subpart Da Hg and Ni Standards?

In December 2000, EPA announced a finding that regulation of Hg emissions from coal-fired Utility Units and Ni emissions from oil-fired Utility Units under CAA section 112 was appropriate and necessary. As explained above, we are proposing today to revise that finding. We continue to believe, however, that the HAP of greatest concern from coal-fired units is Hg, with Ni being the HAP of greatest concern from oil-fired units. In December 2000, based on the record before the Agency, EPA estimated that coal-fired Utility Units in the U.S. emitted approximately 48 tons of Hg into the atmosphere in 1999, and that methylmercury, the end product of Hg deposited to water bodies, is a significant health hazard, particularly to sensitive subpopulations. The EPA also found that Hg emissions could in some cases be reduced through application of control technology. Finally, the record supporting the December 2000 action reveals that oil-fired Utility Units emitted approximately 322 tons of Ni in 1994.

Today's action proposes standards under the regulatory authority of section 111(b), which will regulate Hg (from coal-fired units) and Ni (from oil-fired units) emissions from new units on which construction is commenced after today's date, and emissions guidelines under the authority of section 111(d), which will regulate Hg emissions from existing coal-fired Utility Units and Ni emissions from existing oil-fired Utility Units.

The source of Hg and Ni emissions from these units is the same at both new and existing steam generating units; therefore, in general, the control of these emissions would be the same as well. Throughout this preamble, where clear distinctions arise, the rationales for the EPA actions affecting new and existing units are discussed separately. Otherwise, the discussion applies to the proposed standards and emission guidelines.

2. What Is the Performance of Control Technology on Hg?

Currently, there are no commercially available control technologies specifically designed for reducing Hg emissions. However, available data indicate that controls installed for reducing emissions of PM, SO_2, and NO_X are also effective in some cases in reducing Hg emissions from coal-fired Utility Units. The degree of removal, however, depends (in part) on the rank of coal being burned.

The American Society for Testing and Materials (ASTM) classifies coals by rank, a term which relates to the carbon content of the coal and other related parameters such as volatile-matter content, heating value, and agglomerating properties. The coal-fired electric utility industry combusts the following coal ranks, presented in decreasing order: anthracite, bituminous, subbituminous, and lignite. The HHV of coal is measured as the gross calorific value, reported in British thermal units per pound (Btu/lb). The heating value of coal increases with increasing coal rank. The youngest, or lowest rank, coals are termed lignite. Lignites have the lowest heating value of the coals typically used in power plants. Their moisture content can be as high as 30 percent, but their volatile content is also high; consequently, they ignite easily. Next in rank are subbituminous coals, which also have a relatively high moisture content, typically ranging from 15 to 30 percent. Subbituminous coals also are high in volatile matter content and ignite easily. Their heating value is generally in between that of the lignites and the bituminous coals. Bituminous coals are next in rank, with higher heating values and lower moisture and volatile content than the subbituminous and lignite coals. Anthracites are the highest rank coals. Because of the difficulty in obtaining and igniting anthracite, only a single electric utility boiler in the U.S. burned anthracite as its only fuel in 1999. Because bituminous coal is the most similar coal to anthracite coal based on coal physical characteristics (ash content, sulfur content, HHV), anthracite coal is considered to be equivalent to bituminous coal for the purposes of the proposed rule and, thus, the anthracite-fired unit is considered a bituminous-fired unit for the purposes of the proposed rule.

Although there is overlap in some of the ASTM classification properties, the ASTM method of classifying coals by rank generally is successful in identifying some common core characteristics that have implications for power plant design and operation.

Coal refuse (*i.e.*, anthracite coal refuse (culm), bituminous coal refuse (gob), and subbituminous coal refuse) is also combusted in utility units. Coal refuse refers to the waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material. Previously considered unusable by the industry because of the high ash content and relatively low heat content, it now may be utilized as a supplemental fuel in limited amounts in some units or as the primary fuel in a fluidized bed combustor (FBC). Because of the inherent inability to utilize coal refuse as the primary fuel in anything other than an FBC, it is considered to be a separate coal rank for purposes of the proposed rule.

The rank of coal to be burned has an enormous impact on overall plant design. The goal of the plant designer is to arrange boiler components (furnace, superheater, reheater, boiler bank, economizer, and air heater) to provide the rated steam flow, maximize thermal efficiency, and minimize cost. Engineering calculations are used to determine the optimum positioning and sizing of these components, which cool the flue gas and generate the superheated steam. The accuracy of the parameters specified by the owner/operators is critical to designing and building an optimal plant. The rank of coal to be burned greatly impacts the entire design process. The rank of coal burned also has significant impact on the design and operation of the emission control equipment (*e.g.*, ash resistivity impact on ESP performance).

For the above reasons, one of the most important factors in modern electric utility boiler design involves the differences in the ranks and range of coals to be fired and their impact on the details and overall arrangement of boiler components. Coal rank is so important that plant designers and manufacturers expect to be provided with a complete list of all coal ranks presently available or planned for future use, along with their complete chemical and ash analyses, so that the engineers can properly design and specify plant equipment. The various coal characteristics (*e.g.*, how hard the coal is to pulverize; how high its ash content; the chemical content of the ash; how the ash ''slags'' (fused deposits or resolidified molten material that forms primarily on furnace walls or other surfaces exposed predominantly to radiant heat or high temperature); how big the boiler has to be to adequately utilize the heat content; etc.), therefore, impact on boiler design from the pulverizer through the boiler to the final steam tubes. For a boiler to operate efficiently, it is critical to recognize the differences in coals and make the necessary modifications in boiler components during design to provide optimum conditions for efficient combustion.

Coal-fired units are designed and constructed with different process configurations partially because of the constraints, including the properties of the fuel to be used, placed on the initial design of the unit. Accordingly, these site-specific constraints dictate the process equipment selected, the component order, the materials of construction, and the operating conditions.

Approximately 23 percent of coal-fired Utility Units either (1) co-fire two or more ranks of coal (with or without other fuels) in the same boiler, or (2) fire two or more ranks of coal (with or without other fuels) in the same boiler at different times (1999 EPA ICR). This coal ''blending'' is done generally for one of three reasons: (1) To achieve SO_2 emission compliance with title IV provisions of the CAA, (2) to prevent excessive slagging by improving the heat content of a lower grade coal, or (3) for economic reasons (*i.e.*, coal rank price and availability).

These blended coals, although of different rank, do have similar properties. That is, because of the overlap in various characteristics in the ASTM definitions of coal rank, certain bituminous and subbituminous coals (for example) exhibit similar handling and combustion properties. Plant designers and operators have learned to accommodate these blends in certain circumstances without significant impact on plant operation or control.

The flue gases resulting from the combustion of these different coal ranks can exhibit different Hg emissions characteristics. These Hg emissions characteristics consist of varying percentages of the three relevant forms (or species) of Hg (particulate-bound, oxidized (ionic), and elemental) that makeup the total Hg in the flue gas.

Available source test data shows that combustion of bituminous coal results in Hg emissions that are composed of relatively more Hg^{++} compared to the other coal ranks. Combustion of bituminous coal produces the most particulate-bound Hg of any of the three major coal ranks combusted. Combustion of subbituminous coal results in emissions that are composed of relatively more elemental Hg (compared to bituminous coal), with little particulate-bound Hg (less than half that of bituminous coal emissions). Combustion of lignite coal also results in emissions that are composed of relatively more elemental Hg (compared to bituminous coal) with little particulate-bound Hg (also less than half that of bituminous coal emissions). Available data indicate that emissions from the combustion of coal refuse tends to result almost entirely in particulate-bound Hg (greater than 99 percent for both units tested in the 1999 EPA ICR). With few exceptions, particulate-bound Hg can be removed with PM controls, Hg^{++} can be removed with wet SO_2 controls (FGD scrubbers), but elemental Hg usually shows little to no removal with any existing conventional type of APCD used on utility boilers. However, new technologies such as activated carbon adsorption show promise in removing elemental Hg.

There are five basic types of coal combustion processes used in the coal-fired electric utility industry. These are conventional-fired boilers, stoker-fired boilers, cyclone-fired boilers, integrated gasification combined cycle (IGCC) units, and fluidized bed combustors (FBC).

Conventional boilers, also known as pulverized coal (PC) boilers, have a number of firing configurations based on their burner placement. The basic characteristic that all conventional boilers have in common is that they inject PC and primary air through a burner where ignition of the PC occurs, which in turn creates an individual flame. Conventional boilers fire through many such burners mounted in the furnace walls.

In stoker-fired boilers, fuel is deposited on a moving or stationary grate or spread mechanically or pneumatically from points usually 10 to 20 feet above the grate. The process utilizes both the combustion of fine coal powder in air and the combustion of larger particles that fall and burn in the fuel bed on the grate.

Cyclone-fired boilers use several water-cooled horizontal burners that produce high-temperature flames that circulate in a cyclonic pattern. The burner design and placement cause the coal ash to become a molten slag that is collected below the furnace.

Fluidized bed combustors combust coal, in a bed of inert material (*e.g.*, sand, silica, alumina, or ash) and/or a sorbent such as limestone, that is suspended through the action of primary combustion air distributed below the combustor floor. ''Fluidized'' refers to the state of the bed of material (coal and inert material (or sorbent)) as gas passes through the bed. As the gas flow rate is increased, the force on the fuel particles becomes just sufficient to cause buoyancy. The gas cushion between the solids allows the particles to move freely, giving the bed a liquid-like (or fluidized) characteristic.

Integrated-coal gasification combined cycle units are specialized units in which coal is first converted into synthetic coal gas. In this conversion process, the carbon in the coal reacts with water to produce hydrogen gas and CO. The synthetic coal gas is then combusted in a combustion turbine which drives an electric generator. Hot gases from the combustion turbine then pass through a waste heat boiler to produce steam. This steam is fed to a steam turbine connected to a second electric generator.

Available information indicates that Hg emissions from coal-fired Utility Units are minimized in some cases through the use of PM controls coupled with an FGD system. For bituminous-fired units, use of a selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR) system may further enhance Hg removal. This does not appear to be the case for subbituminous- and lignite-fired units. The EPA believes the best potential way of reducing Hg emissions from IGCC units is to remove Hg from the syngas before combustion. An existing industrial IGCC unit has demonstrated a process, using sulfur-impregnated AC carbon beds, that has proven to yield 90 to 95 percent Hg removal from the coal syngas. This technology could potentially be adapted to the electric utility IGCC units. The EPA believes this to be a viable option for IGCC units.

3. What Is the Performance of Control Technology on Ni?

The EPA analyzed the data available on the fuel, process, emission profiles, and APCD for oil-fired units at existing affected sources. An oil-fired electric utility boiler combusts fuel oil exclusively, or combusts fuel oil at certain times of the year and natural gas at other times (not simultaneously). The choice of when to combust oil exclusively or to alternate between oil and natural gas at a single boiler is usually based on economics or fuel availability (including seasonal availability). The ASTM classifies oils by ''grade,'' a term which relates to the amount of refinement that the oil undergoes. The level of refinement directly affects the Ni and carbon content of the oil and other related parameters such as sulfur content, heating value, and specific gravity. The most refined fuel oil used by the oil-fired electric utility industry is known as No. 2 fuel oil (also known as distillate oil or medium domestic fuel oil). The least refined fuel oil used by the oil-fired electric utility industry is known as No. 6 fuel oil (also known as residual oil or Bunker C oil). By comparison, No. 2 fuel oil is lower in Ni, sulfur, ash content, and heating value but higher in carbon content than No. 6 fuel oil. Only a handful of boilers (8 of 218) fire No. 2 distillate fuel oil exclusively. (2001 EIA data) However, 28 out of 218 boilers fire No. 2 distillate fuel oil and No. 6 (residual) fuel oil in the same boiler (either simultaneously or at separate times).

The proposed standard of performance for Ni from new oil-fired units was determined by analyzing the emissions data available. The data were obtained from the Utility RTC which provided information indicating that Ni was the pollutant of concern due to its high level of emissions from oil-fired units and the potential health effects resulting from exposure to it. The EPA examined available test data and found that ESP-equipped units can effectively reduce Ni. The proposed standard of performance for Ni is based on the level of control demonstrated by the top performing existing units with regard to removal of Ni. The test data were converted to an output-based limit using an efficiency factor.

The EPA is sensitive to the fact that some sources burn fuels containing very little Ni. Therefore, EPA solicits comment on a Ni-in-oil limit that would be equivalent to the proposed stack value of 0.0005 lb/MWh gross. With a limit on the amount of Ni in the oil, a new source could choose to comply with an alternate oil-content-based Ni emission limitation instead of the stack Ni emission limit to meet the proposed rule. Such an alternate Ni-in-oil limit could be useful where Ni constituent levels are low in the fuel.

Dual-Fired (Oil/Natural Gas) Units. The EPA is aware that an oil-fired unit may fire oil at certain times of the year and natural gas at other times. The choice of when to fire oil or natural gas is usually based on the economics or availability of fuel (*i.e.,* seasonal considerations). The EPA considers a unit to be an oil-fired unit if (1) it is equipped to fire oil and/or natural gas, and (2) it fires oil in amounts greater than or equal to 2 percent of its annual fuel consumption. This 2 percent value is intended to represent that amount of oil that a true natural gas-fired unit might use strictly for start-up purposes on an annual basis. The EPA solicits comment on whether this two percent breakpoint is a reasonable basis for allowing those units that use oil only for startup purposes to be exempted from regulation under the proposed rule.

4. What Is the Regulatory Approach?

Subpart Da Hg emission standards. In selecting a regulatory approach for formulating emission standards to limit Hg emissions from new coal-fired steam generating units, the performance of the Hg control technologies discussed above were considered. The technical basis (*i.e.,* BDT) selected for establishing Hg emission limits for new sources is the use of effective PM controls and wet or dry FGD systems on subbituminous-, lignite-, and waste coal-fired units and effective PM controls, wet or dry FGD systems, and SCR or SNCR on bituminous-fired units, and activated carbon beds for IGCC units.

Section 111(b)(2) of the CAA allows the Administrator to ''* * * distinguish among classes, types, and sizes within categories of new sources * * *'' in establishing standards when differences between given types of sources within a category lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques. After examining a number of possible subcategorization options, EPA identified two basic ways to subcategorize coal-fired Utility Units, by coal rank or by process type.

Subcategorization by coal rank. Subcategorization by individual coal rank addresses the differences in the characteristics of the Hg emissions (*i.e.,* speciation of Hg) and the resulting ability to control Hg as well as accommodating the various design and control constraints resulting from the various coal ranks.

Subcategorization by process type. Another option is to subcategorize by process type. Different process types could create potential emissions differences which lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques. Although conventional-, stoker-, and cyclone-fired boilers use different firing techniques, the Hg emissions characteristics of these boilers are similar (given that common ranks of coal are fired) and, therefore, the units can be grouped together. Although these units fire a variety of coal ranks they have only combusted coal refuse in lesser amounts as a secondary fuel source.

Based on their unique firing designs, FBC units employ a fundamentally different process for combusting coal from that employed by conventional-, stoker-, or cyclone-fired boilers. Fluidized-bed combustors are capable of combusting many coal ranks including coal refuse. For these reasons, FBC units can be considered a distinct type of boiler. However, the Hg emissions test data results for FBC units were not substantially different from those at similarly-fueled conventionally-fired units with similar emission levels, either in mass of emissions or in emissions characteristics.

Integrated gasification combined cycle units combust a synthetic coal gas. No coal is directly combusted in the unit during operation (although a coal-derived fuel is fired), and, thus, IGCC units are a distinct class or type of boiler for the proposed rule.

Based on the above discussion, the EPA is proposing to use five subcategories for establishing Hg limits based on a combination of coal rank and

process type in this rule (bituminous coal, subbituminous coal, lignite coal, coal refuse, and IGCC).

The EPA's review of the available emission data shows that Hg emissions from new coal-fired units can be reduced to the following:

Bituminous units: 0.61 lb/TBtu heat input;
Subbituminous units: 2.0 lb/TBtu heat input;
Lignite units: 6.3 lb/TBtu heat input;
Waste coal units: 0.11 lb/TBtu heat input;
IGCC units: 2.0 lb/TBtu heat input.

Mercury emissions from new oil- and gas-fired units are not covered by the proposed rule.

Subpart Da Ni emission standards. In selecting a regulatory approach for formulating emission standards to limit Ni emissions from new oil-fired steam generating units, the performance on Ni of the PM control technologies discussed above were considered. The technical basis (*i.e.,* BDT) selected for establishing Ni emission limits for new sources is the use of ESP units or oils low in Ni content.

The EPA's review of the available emission data shows that Ni emissions from new oil-fired units can be reduced to 84 lb/TBtu heat input.

5. What Are the Subpart Da Hg and Ni Emission Standards?

Based on available performance data analyses from the 1999 ICR for coal-fired Utility Units, the Administrator has concluded that the application of fabric filters or ESP units along with wet or dry FGD is considered to be the most effective Hg control technology for units firing subbituminous, lignite, or waste coals; and that the application of fabric filters or ESP units, wet or dry FGD systems, and SCR is considered to be the most effective Hg control technology for units firing bituminous coals. For IGCC units (regardless of coal rank fired), the Administrator has concluded that use of a carbon bed is considered to be the most effective Hg control technology. These controls represent the best system of emissions reductions (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact, and energy requirements).

Based on available performance data and cost analyses, the Administrator has concluded that the application of ESP units or oils containing a low Ni content is considered to be the most effective Ni control technology for oil-fired units. These controls represent the best system of emissions reductions (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact, and energy requirements).

6. How Did EPA Select the Format for the Proposed Standards?

Based on the analyses and discussion presented earlier, EPA has selected an output-based format for the proposed new-source rule. The Administrator is proposing today Hg emission limits for new coal-fired Utility Units as follows:

Bituminous units: 0.0060 GWh gross;
Subbituminous units: 0.020 lb/GWh gross;
Lignite units: 0.062 lb/GWh gross;
Waste coal units: 0.0011 lb/GWh gross;
IGCC units: 0.020 lb/GWh gross.

Based on the available performance data, cost analysis, and the above calculation, the Administrator is proposing today Ni emission limits for new oil-fired Utility Units as follows: 0.0008 lb/MWh gross.

7. How Did EPA Determine Testing and Monitoring Requirements for the Proposed Standards?

The CAA requires EPA to develop regulations that ensure initial and continuous compliance. Testing and monitoring requirements allow EPA to determine whether an affected source is operating in compliance with an applicable emission limitation/standard. This section discusses how EPA selected the proposed testing and monitoring requirements used to determine compliance with the Hg and Ni emission limits that are specified in the proposed rule.

Mercury testing and monitoring requirements. The proposed rule would establish Hg emission limits for coal-fired units. The format selected for these Hg emission limits is a 12-month rolling average Hg emission level expressed in units of lb/TBtu or lb/MWh. Therefore, appropriate testing or monitoring requirements for determining the amount of Hg emitted from an affected unit throughout the compliance averaging period must be included in the rule.

The most direct means of demonstrating compliance with an emission limit is by the use of a CEMS that measures the pollutant of concern. The EPA considers other testing or monitoring options when acceptable CEMS are not available for the intended application or when the impacts of including such CEMS requirements in the proposed rule are considered by EPA to be unreasonable. In determining whether to require the use of other testing or monitoring options in lieu of CEMS, it is often necessary for EPA to balance more reasonable costs against the quality or accuracy of the actual emissions data collected.

There are several approaches to Hg monitoring that EPA has identified for possible use in this rule to determine compliance with the proposed Hg emission limits. One option is to use a CEMS that combines both automated sampling and analytical functions in a single system to provide continuous, real-time Hg emission data. Mercury CEMS are currently available from several manufacturers. These Hg CEMS are similar to most other types of instruments used for continuous monitoring of pollutants from combustion processes, in that the combustion gas sample is first extracted from the stack and then transferred to an analyzer for analysis. In general, the Hg CEMS now available can be distinguished by the Hg measurement detection principle used (*e.g.,* atomic adsorption, atomic fluorescence, x-ray fluorescence). Capital costs for a Hg CEMS are currently estimated to range from approximately $95,000 to $135,000, depending on the manufacturer and model selected. The annual costs to operate and maintain a Hg CEMS are estimated to range from $45,000 to $65,000, again depending on the manufacturer and model selected.

A second option is to use a long-term sampling method that collects a cumulative Hg sample by continuously passing a low-flow sample stream of the combustion process flue gas through a Hg trapping medium (*e.g.,* an activated carbon tube). This sampling tube is then periodically removed (*e.g.,* after a day or up to 1 month) and replaced with a tube filled with fresh trapping medium. The removed sampling tube is then sent to a laboratory where the trapping medium is analyzed for its Hg content. This method, like using a Hg CEMS, is capable of providing data on the Hg emissions from a combustion process on a continuous basis, but unlike a Hg CEMS, the data are not reported on a real-time basis. Using the long-term sampling method, the Hg collected in the sampling tube is integrated over a much longer sampling period (*i.e.,* 1 to 7 days for the AC tube versus less than 15 minutes for the CEMS). The capital cost for a gas metering system and Hg trapping medium is estimated to be approximately $18,000. The annual costs for periodic sampling tube replacement and for the laboratory Hg analysis range from approximately $65,000 to $125,000 depending upon quality assurance and quality control (QA/QC) requirements and frequency of sample tube replacement.

Finally, a third monitoring option is to use one of the manual stack test methods available for measuring Hg emissions from combustion processes on an intermittent basis. The existing voluntary consensus stack test method ASTM Method D6784–02 (commonly known as the Ontario-Hydro method) is currently the method of choice for measuring Hg species in the flue gas from Utility Units. Another method for measuring total (*i.e.*, not speciated) Hg is EPA Reference Method 29. This method involves a technician extracting a representative flue gas sample over a relatively short period of time (*e.g.*, a few hours) using a sampling train consisting of a nozzle and probe, a filter to collect particulate matter, and a liquid solution and/or reagent to capture gas-phase Hg. After sampling, the filter and sorption media are prepared and analyzed for Hg in a laboratory. These test methods could be applied to a Hg monitoring program at electric utility plants by performing a manual stack test using ASTM Method D6784–02 or EPA Reference Method 29 at some specified periodic interval throughout the compliance averaging period (*e.g.*, perform a stack test daily, weekly, biweekly, monthly). The cost to conduct a single ASTM Method D6784–02 typically ranges from $15,000 to $17,000 depending on site conditions. Annual costs will depend on the frequency with which the stack test is required to be performed during the compliance averaging period. For example, if the test is required once per week, the total annual cost would be as much as $780,000 (52 tests in a 12-month period at $15,000 per test).

The EPA evaluated each of the above Hg monitoring options with respect to its suitability for the measurement of the Hg emission data needed for determining compliance with the 12-month rolling average Hg emission limit. The EPA rejected from further consideration the third option, intermittent monitoring using manual stack test methods. Use of this monitoring approach would place significantly higher labor requirements and monitoring costs on facility owners/operators than the other two options in order to perform an adequate number of source tests throughout the compliance averaging period to demonstrate with reasonable confidence that the applicable Hg emission limit value was being achieved.

Both of the remaining two options would provide the necessary data to calculate the total Hg emissions from an affected source for each 12-month compliance averaging period. While the CEMS would provide these data on a real-time basis, EPA concluded that having real-time data is not mandatory for determining compliance with an emission limit based on a 12-month rolling average. Total Hg emissions from an affected source by month are needed to compute the rolling 12-month average Hg emission value. With regular scheduled replacement and timely analysis of sampling tubes, total monthly Hg emissions can readily be obtained using the long-term sampling method.

The EPA then compared the costs of applying the Hg CEMS and long-term monitoring options to Utility Units. While the CEMS have significantly higher capital costs, the automated analyses directly by the instrument eliminates the need and cost for separate analyses of the collected sampling tubes in a laboratory required by the long-term sampling method. Overall, EPA determined that the total costs of using either monitoring method to determine compliance would be similar for a given site. Selection of which monitoring method should be used at the site will depend on site-specific conditions and owner/operator preferences. Because both monitoring methods will collect the Hg emission data necessary to determine compliance with the proposed Hg emission limit and the costs of either option are reasonable, EPA decided to allow the owner/operator flexibility under the proposed rule to choose to use either Hg CEMS or long-term sampling monitoring as best suits their site conditions and preferences.

An owner/operator electing to use a CEMS to comply with the rule would be allowed to use any CEMS that meets the requirements in ''Performance Specification 12A, Specifications and Test Procedures for Total Vapor-phase Mercury Continuous Monitoring Systems in Stationary Sources'' (PS–12A). This performance specification is proposed as part of this rulemaking and we request comment on continuous monitoring of Hg emissions according to the requirements in the proposed performance specification.

Those owners/operators electing to use long-term Hg monitoring would be required to follow the requirements in Method 324, ''Determination of Vapor Phase Flue Gas Mercury Emissions from Stationary Sources Using Dry Sorbent Trap Sampling'' when it is promulgated. Method 324 is proposed as part of this rulemaking to be added to 40 CFR part 60, appendix A. We request comments on the requirements in proposed Method 324 for Hg measurement using long-term sampling.

Continuous compliance requirements are required under every NSPS so that EPA can determine whether an affected source remains in compliance with the applicable emission limitation/standard following the initial compliance determination. In the case of the proposed NSPS, the format for the Hg emission limit is a 12-month rolling average limit. The same monitoring requirements used to establish initial compliance of an affected electric utility unit with the applicable Hg emission limit at the end of the first 12-month period following the facility's compliance date serve to demonstrate continuous compliance with the Hg emission limit with the computation of each new 12-month rolling average value each month thereafter. Thus, no additional continuous compliance Hg monitoring requirements beyond those previously discussed are required for the proposed rule.

The EPA is concerned about monitoring costs for units with low Hg emissions rates, and does not desire to adopt a monitoring scheme where the costs are disproportionate to the costs of compliance with the MACT emissions limitations. For these units (*e.g.*, those emitting under 25 pounds per year) the EPA may consider reduced monitoring frequencies and lower cost monitoring requirements, since the need for accuracy is reduced for such units. For example, the EPA is concerned about the merits of requiring an expenditure of $100,000 per year to monitor releases when the costs of substantive compliance is far less. The Agency requests comments and related data upon which to establish an alternate reporting scheme.

Nickel testing and monitoring requirements. The proposed rule would establish Ni emission limits for oil-fired units. The EPA selected a different format for the Ni emission limits than is proposed for the Hg emission limits. The Ni emission limits are maximum allowable emission limits not to be exceeded, expressed in lb/TBtu or lb/MWh.

The EPA selected the proposed testing requirements to determine compliance with the Ni emission limits to be consistent with existing procedures used for the electric utility industry. Method 29 in appendix A to 40 CFR part 60 is an EPA reference test method that has been developed and validated for the measurement of Ni emissions from stationary sources. For sampling and analysis of the gas stream, the following EPA reference methods would be used with Method 29: Method 1 to select the sampling port location and the number of traverse points; Method

2 to measure the volumetric flow rate; Method 3 for gas analysis; and Method 4 to determine stack gas moisture. Method 19 specifies the procedure for collecting the necessary fuel data to be used with the Method 29 Ni measurements from the source test to compute the Ni emission rate expressed in units of lb/TBtu.

As an alternative under the proposed rule, an owner/operator of an existing oil-fired source could choose to comply with the applicable Ni emission limit expressed in lb/MWh.

To address the need for continuous compliance requirements for the proposed Ni emission limits, EPA considered the availability and feasibility of a number of Ni monitoring options ranging from direct monitoring of Ni emissions, to process parameter monitoring, to control device parameter monitoring. Monitors for continuously measuring Ni emissions have not been demonstrated in the U.S. for the purpose of determining compliance. Therefore, EPA did not consider further the use of any continuous monitoring for Ni for the proposed rule.

Another option used in other NSPS for demonstrating continuous compliance is to monitor appropriate process and/or control equipment operating parameters. These parameters are established during the initial, and any subsequent, stack test. Process parameters were not selected as indicators for Ni emissions from Utility Units because a direct correlation does not exist between combustion or electricity production parameters and Ni emission rates from a given unit.

Monitoring of PM control device operating parameters is used in other NSPS established for combustion processes and other source categories that include PM emission limits. The EPA decided to also use this continuous monitoring approach to demonstrate continuous compliance with the applicable Ni emission limits set forth in the proposed rule. The selected operating parameters for the PM control device used by oil-fired Utility Units (*e.g.*, ESP) are reliable indicators of control device performance. The EPA believes that reasonable assurance of compliance with the emission limits proposed for this NSPS can be achieved through appropriate monitoring and inspection of the operation of the APCD that have been demonstrated by an initial performance test to achieve the applicable Ni emission limits under the rule.

Compliance calculations. For cogeneration units, steam is also generated for process use. The energy content of this process steam must also be considered in determining compliance with the output-based standard. This consideration is accomplished by taking the net efficiency of a cogeneration unit into account. Under a Federal Energy Regulatory Commission (FERC) regulation, the efficiency of cogeneration units is determined from ''* * * the useful power output plus one half the useful thermal output * * *,'' (18 CFR part 292, 205). To determine the process steam energy contribution to net plant output, a 50 percent credit of the process steam heat is necessary.

Therefore, owners/operators of cogeneration units subject to the proposed rule would need to monitor the portion of their net plant output that is process steam so that they can take the 50 percent credit of the energy portion of their process steam net output. For example, a cogeneration unit subject to the rule measures its net electrical output over a compliance period, as 30,000 MWh. During the same period the unit burns coal that provides 750 billion Btu input to its furnace/boiler, and emits 0.2 lb Hg. Using equivalents found in 40 CFR part 60 for electric utilities (*i.e.*, 250 million Btu/hr input to a boiler is equivalent to 73 MWe input to the boiler; 73 MWe input to the boiler is equivalent to 25 MWe output from the boiler; therefore, 250 million Btu input to the boiler is equivalent to 25 MWe output from the boiler) the 50 percent credit could be found as follows. The net output calculation would be 750 billion Btu × (25 MWe output/250 million Btu/hr input) = 75,000 MWh equivalent electrical output from the boiler over the compliance period. Of this amount, 30,000 MWh was produced as electricity sent to the grid, leaving 45,000 MWh as the energy converted to steam for process use. Half of this amount is 22,500 MWh. The unit's Hg CEM records a total of 0.2 lb Hg over the same compliance period. The adjusted Hg emission rate is then: 0.2 lb Hg/(30,000 MWh + 22,500 MWh) = 3.8×10^{-6} lb Hg/MWh. Cogeneration units would have to account for the process steam portion of their emissions in the same manner for PM emissions as well.

8. How Did EPA Determine the Compliance Times for the Proposed Standards?

New sources are required to be in compliance either upon start up or the effective date of this rule, whichever is later.

9. How Did EPA Determine the Required Records and Reports for the Proposed Standards?

Under section 114(a) of the CAA, EPA may require owners/operators of affected sources subject to a NSPS to maintain records as well as prepare and submit notifications and reports to the EPA. In addition, section 504(a) of the CAA mandates that sources required to obtain a title V permit submit a report setting forth the results of any required monitoring no less often than every 6 months. The general recordkeeping, notification, and reporting requirements for all NSPS are specified in 40 CFR 60.7 and 40 CFR 60.19 of the General Provisions, if incorporated into the proposed rule. The recordkeeping, notification, and reporting requirements for the proposed rule were selected to include all of the applicable records, notifications, and reports specified by the General Provisions requirements. Additional requirements were included in the proposed rule that are necessary to ensure that a given affected source is complying with the emission limits from the correct subcategory.

The proposed rule would also require that the owner/operator keep monthly records for each affected source listing the type of fuel burned, the total fuel usage, and the fuel heating value. Additional recordkeeping would be required for those owners/operators electing to comply with a fuel blending emission limit. The owner/operator would be required to maintain records of all compliance calculations and supporting information.

D. Rationale for the Proposed Hg Emission Guidelines

1. What Is the Authority for Cap-and-Trade Under Section 111(d)?

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

of * * * section (111),'' the term ''standard of performance'' to mean

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

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

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

The term ''standard of performance'' is not explicitly defined to include or exclude an emissions cap and allowance trading program. In today's action, EPA proposes to interpret the term ''standard of performance,'' as applied to existing sources, to include a cap-and-trade program. This interpretation is supported by a careful reading of the section 111(a) definition of the term, quoted above: A requirement for a cap-and-trade program (i) constitutes a ''standard for emissions of air pollutants'' (*i.e.,* a rule for air emissions), (ii) ''which reflects the degree of emission limitation achievable'' (*i.e.,* which requires an amount of emissions reductions that can be achieved), (iii) ''through application of (a) * * * system of emission reduction'' (*i.e.,* in this case, a cap-and-trade program that caps allowances at a level lower than current emissions).[12]

Nor do any other provisions of section 111(d) indicate that the term ''standard of performance'' may not be defined to include a cap-and-trade program. Section 111(d)(1)(B) refers to the ''implementation and enforcement of such standards of performance,'' and section 111(d)(1) refers to the State ''in applying a standard of performance to any particular source,'' but all of these references readily accommodate a cap-and-trade program.

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

Even if the 302(l) definition applied to the term ''standard of performance'' as used in section 111(d)(1), EPA believes that a cap-and-trade program meets the definition. A cap-and-trade program with an overall cap set below current emissions is a ''requirement of * * * emission reduction.'' Moreover, it is a requirement of ''continuous'' emissions reductions because all of a source's emissions must be covered by allowances sufficient to cover those emissions. That is, there is never a time when sources may emit without needing allowances to cover those emissions.[13]

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

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

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

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

Since the passage of the 1990 Amendments to the CAA, EPA has had significant experience with the cap-and-trade program for utilities. The 1990 Amendments provided, in title IV, for the acid rain program, a national cap-and-trade program that covers SO_2 emissions from utilities. title IV requires sources to hold allowances for each ton of emissions, on a one-for-one basis. The EPA allocates the allowances for annual periods, in amounts initially determined by the statute, and that decrease further at a statutorily specified time. This program has resulted in an annual reduction in SO_2 emissions from utilities from 15.9 million tons in 1990 (the year the Amendments were enacted) to 10.2 million tons in 2002 (the most recent year for which data is available). Emissions in 2002 were 9 percent lower than 2000 levels and 41 percent lower than 1980, despite a significant increase in electrical generation. As discussed elsewhere, at full implementation after 2010, emissions will be limited to 8.95 million tons, a 50 percent reduction from 1980 levels. The Acid Rain program allowed sources to trade allowances, thereby maximizing overall cost-effectiveness.

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

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

[13] This interpretation of the term ''continuous'' is consistent with the legislative history of that term. *See* H.R. Rep. No. 95–294 at 92, *reprinted in* 4 Congressional Research Service, A Legislative History of the Clean Air Act Amendments of 1977, 2559.

primarily from utilities.[14] These programs are contained in SIP that EPA has approved; and EPA is administering the trading programs. However, for most States, the requirements do not need to be implemented until May, 2004.

The success of the Acid Rain cap-and-trade program for utility SO_2 emissions, which EPA duplicated in large measure with the NO_X SIP Call cap-and-trade program for, primarily, utility NO_X emissions, leads EPA to propose to conclude that a cap-and-trade program for Hg emissions from utilities qualifies as the ''best system of emission reductions'' that ''has been adequately demonstrated.'' A market system that employs a fixed tonnage limitation (or cap) for Hg sources from the power sector provides the greatest certainty that a specific level of emissions will be attained and maintained since a predetermined level of reductions is ensured. The EPA will administer a Hg trading program and will require the use of continuous emissions monitoring systems (CEMS) or an appropriate long-term method that will allow both EPA and sources to track progress, ensure compliance, and provide credibility to the trading component of the program. The advantages of the Hg trading program are discussed further below. We ask for comments on all aspects of this approach under section 111(d).

2. What Is the Regulatory Approach for Existing and New Sources?

What Are the National Hg Budget and Source Emission Limits?

Mercury budget overview. Our primary goal in this rulemaking is to reduce power plant emissions of Hg by 70 percent from today's levels by 2018. We are proposing to accomplish this goal by setting a 15 ton cap on these emissions in 2018. Under our proposal, the 2018 cap would be a permanent cap that could not be exceeded, regardless of future growth in the energy sector. Thus, the cap would effectively become more stringent as more and more plants are required to keep their collective emissions below 15 tons.

We also are proposing to set a near-term cap in 2010 at a level that reflects the maximum reduction in Hg emissions that could be achieved through the installation of FGD and SCR units that will be necessary to meet the 2010 caps for SO_2 and NO_X in our proposed IAQR. Although we know that FGD and SCR units reduce Hg emissions (as well as SO_2 and NO_X), there is significant uncertainty about the extent of the Hg reductions that these controls could achieve by 2010. Thus, we are seeking technical information that would allow us to establish an appropriate Hg cap in 2010.

The EPA believes that a carefully designed ''multi-pollutant'' approach—a program designed to control NO_X, SO_2, and Hg at the same time—is the most effective way to reduce emissions from the power sector. One key feature of this approach is the interrelationship of the timing and cap levels for SO_2, NO_X, and Hg. Today, we know that power plants can reduce their emissions of all three pollutants by installing FGD (which controls SO_2 and Hg emissions) and SCR (which controls NO_X and Hg). With respect to the first phase of Hg reductions, we have designed this proposal to take advantage of the combined emission reductions that these technologies provide. Therefore, we believe that the Phase I Hg cap should be set at a level that reflects the Hg reductions that would be achieved from the SO_2 and NO_X cap levels and corresponding control requirements in the IAQR that we also are proposing today.

A phase-one cap based on this approach would set a standard of performance based on the best system of emissions reduction that has been adequately demonstrated, consistent with section 111(d) of the Clean Air Act. Research currently indicates that Hg control technologies other than FGD and SCR—most notably activated carbon injection (ACI) and breakthrough technologies (*e.g.,* chemical systems to enhance removal efficiencies for wet scrubbers)—may one day allow facilities to reliably reduce Hg emissions to levels significantly below the levels achieved through application of FGD and SCR needed to satisfy SO_2 and NO_X control requirements. However, these technologies have not been adequately demonstrated on full-scale power plants. Moreover, current information on these technologies is not sufficient for us to conclude that they will be adequately demonstrated by 2010. Therefore, we believe that the 2010 cap for Hg should be set at a level that can be achieved through the installation of FGD and SCR needed to meet the 2010 SO_2 and NO_X caps in the proposed IAQR. Requiring additional FGD and SCR beyond those needed to meet the transport rule in order to further reduce Hg emissions by 2010 is not reasonable because the incremental cost of such a requirement for additional Hg reductions would be extremely high and the capacity of the equipment suppliers may be overwhelmed.[15]

Consistent with this framework, we are seeking comment and specific technical information concerning the 2010 cap level that should be set for Hg in the final rule. Almost 2 years ago, the Administration proposed Clear Skies legislation that would have established a 26 ton Hg cap in 2010. This cap was based on several factors, including modeling and policy analysis and technical information that was available at that time. Our most recent analysis, based on the most recent technical information, suggests that Hg emissions would be reduced to approximately 34 tons as a result of the FGD and SCR that will be installed to meet the 2010 caps for SO_2 and NO_X in the proposed IAQR. Modeling done by the Energy Information Agency (EIA) suggests that the controls required under our proposed IAQR would not reduce Hg to the extent that EPA is projecting. We are also aware that some stakeholders have recommended near-term Hg reductions that are lower than our estimates.

We recognize that there is and will be for the immediate future uncertainty about all these estimates. To a large extent, this uncertainty exists because we have relatively little direct experience and data about the Hg reductions that can be achieved through different combinations of FGD and SCR on different boiler types burning different ranks of coal, and because there is a high degree of variability in the data that we do have. For example, based on the ICR data, it appears that plants with very similar configurations, and that burn similar ranks of coal, often achieve significantly different levels of Hg control. Thus, if we receive additional technical information, we may be able to find that plants can better optimize their FGD and SCR units to achieve greater reductions in their Hg emissions than we currently estimate. We therefore seek any technical information, including information

[14] Non-electricity generating units (EGU) are also included in the States' programs.

[15] Analysis conducted in support of the proposed IAQR predicts that SO_2 scrubbers will be installed on 48.7 GW of existing coal-fired capacity to comply with the Phase I cap. The analysis also predicts that SCRs will be installed on 24.1 GW of capacity to reduce NO_X emissions. In addition, we predict that existing SCRs that are currently operated on a seasonal basis (*i.e.,* for the ozone season) will under the IAQR be operated for the entire year. These technologies (FGD and SCR) have been developed to reduce SO_2 and NO_X emissions. However, they do realize collateral reductions in Hg, although these reductions are variable (and somewhat uncertain) across types of coal and other control technologies used for treatment. The available modeling suggest that these NO_X and SO_2 controls are predicted to reduce Hg emissions from the power sector to a level of approximately 34 tons per year.

about incremental costs and benefits, that provides the basis for any of the levels mentioned above or other proposals for a near-term cap.

As noted above, EPA is proposing a 15 ton cap in 2018 from coal-fired electric generating facilities. This proposed cap reflects a level of Hg emissions reduction that almost certainly exceeds the level that would be achieved through the installation of FGD and SCR needed to meet the SO_2 and NO_X caps in the proposed IAQR. We conclude that this approach is warranted because we fully expect other Hg air pollution control technologies such as ACI and/or one or more of the breakthrough technologies will have been adequately demonstrated before 2018, making it possible to begin achieving much greater reductions in Hg between 2010 and 2018. This conclusion relies on the fact that the small number of current-day pilot scale ACI projects at Utility Units and the innovative technologies will yield information that will be usable in implementing similar pilot scale projects at other facilities. Data from these pilot studies ultimately will allow companies to design full scale applications that will provide reasonable assurance that emissions limitations can be reliably achieved over extended compliance periods. We do not believe that such full scale technologies can be developed and widely implemented within the next 6 years; however, it is reasonable to assume that this can be accomplished over the next 14 years.

Our proposed 15 ton cap in 2018 is grounded largely in the modeling completed in support of the President's Clear Skies initiative. This modeling suggests that, assuming technologies such as ACI become available, such a cap will create an incentive for certain plants to install these newer technologies. It also suggests that such controls should not have any significant impact on power availability, reliability, or pricing. Nor should a 15-ton cap cause any significant shift in the fuels currently utilized by power plants or in the source of these fuels. Sensitivity analyses indicate that a more stringent cap could have potentially significant impacts on fuels and/or power availability, reliability, or pricing. Less stringent caps do not appear warranted based on our expectations about technology development and our modeling analysis of the potential impacts of the 15-ton cap.

The Agency continues to investigate whether the mandatory 70 percent reduction in Hg emissions will be adequate to eliminate public health risks from local Hg deposition near plants because of scientific and technical uncertainties. The Agency requests comment on this issue.

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

The EPA has concern about Utility Units with low Hg emissions rates (*e.g.*, emitting less than 25 pounds per year) because the new, Hg-specific control technologies that we expect to be developed prior to the Phase II cap deadline may not practicably apply to such units period. Our data indicate that the 396 smallest emitting coal-fired Utility Units currently account for less than 5 percent of total Hg emissions. There is reason to believe that the 15 ton Phase II cap can be achieved in a cost-effective manner, even if the lowest emitting 396 units are excluded from coverage under this cap. Thus, the EPA is soliciting comment on the possibility of excluding from the Phase II cap units with low Hg emissions rates (*e.g.*, emitting less than 25 pounds per year).

In today's notice of proposed rulemaking, EPA is also proposing that allowances are allocated to affected Utility Units based on the proportionate share of their baseline heat input to total heat input of all affected units. For purposes of allocating the allowances, each unit's baseline heat input is adjusted to reflect the ranks of coal combusted by the unit during the baseline period. The sum of the unit emission allowances in a State would be considered the State's emissions budget. If States choose not to participate in the trading program, the State budgets and unit emission allocations will become the required maximum emission limit. States also can require emissions reductions beyond those required by the State budget and unit emission limits.

As discussed elsewhere in this preamble, new sources will comply with NSPS standards for Hg. In addition, new sources will be covered under the Hg cap of the trading program, and will be required to hold allowances equivalent to the product of their NSPS and baseline heat input. The EPA proposes that these sources not receive an adjustment to their allocated share of allowances since they are required to meet NSPS, which may increase total emissions but will maintain required emissions rates.

Rationale for source level limits (allowances). Unit-level emissions limits will be proposed in a supplemental notice entitled ''Emission Guidelines and Compliance Times for Coal-fired Electric Utility Steam Generating Units.'' If a State chooses to participate in the trading program, these unit-level emission limits can be adopted as unit-level allocations for the trading program. Additionally, the trading program provides the individual States the discretion in choosing how to allocate their respective budget allocations.

Different ranks of coal may achieve different Hg reductions depending on the control equipment installed at the unit. In order to distribute unit limits equitably, EPA is proposing that Hg emission limits (allowances if State is participating in a trading program) are distributed to existing coal units based on their share of total heat input. This is then adjusted to reflect the concern that the installation of PM, NO_X, and SO_2 control equipment on different coal ranks results in different Hg removal.

The adjustment factors of 1 for bituminous, 1.25 for subbituminous, and 3 for lignite coals are based on the expectation that Hg in the coal ranks reacts differently to NO_X and SO_2 control equipment and that the heat input of the different coal ranks varies. The conclusion that Hg in each of the coals reacts differently to NO_X and SO_2 control equipment was based on information collected in the ICR as well as more recent data collected by EPA, DOE, and industry sources. This information, which was collected from units of various coal ranks and control equipment configuration, indicated differing levels of Hg removal. The test data indicated that installation of PM, NO_X, and SO_2 controls on plants burning bituminous coals resulted in greater Hg reduction on average than plants burning subbituminous coals or lignite coals. Likewise, the test data indicated that installation of PM, NO_X, and SO_2 controls on plants burning subbituminous coals resulted in somewhat greater Hg removal than plants burning lignite coals. On average, units burning lignite coal showed the least Hg removal of the three coal ranks. See section C.4 for further discussion on subcategorization approaches considered under this proposal.

Under the proposed emission limit or allocation methodology, bituminous units would be allocated a share of the allowances 1.0 times their share of the overall heat input, subbituminous units would be allocated a share of the allowances 1.25 times their share of the overall heat input, and lignite units

would be allocated a share of the allowances 3.0 times their share of the overall heat input. These adjustment factors are considered to be directionally correct based on the test data currently available; however, we realize that these factors do not in all cases accurately predict relative rates of Hg emissions from Utility Units with NO_X and SO_2 controls. Our goal, however, is not to have the factors achieve such a result. Rather, the factors are intended to equitably distribute allowances to the affected industry. The EPA is taking comment on the appropriateness of these adjustment factors. Since new sources are required to meet NSPS, EPA is proposing new sources will not receive an adjustment to their allocated share.

Distribution of State budgets. The trading program establishes a cap on Hg emissions for affected electric generating units of 15 tons starting in 2018. The proposed unit level emission limits (allocations) are the basis for establishing State budgets with the State budgets equaling the total of the individual unit emission limits in a given State (*see* Table 5 of this preamble below). States also have the flexibility to not participate in the trading program or require more stringent Hg emissions reductions. For States that do not participate in the trading program, the proposed unit level allocations will become fixed, unit level emissions limitations.

TABLE 5.—DISTRIBUTION OF STATE BUDGETS

State	Phase II budget (tons)
Alabama	0.506
Alaska	0.002
Arizona	0.289
Arkansas	0.202
California	0.016
Colorado	0.277
Connecticut	0.023
Delaware	0.029
District of Columbia	0.000
Florida	0.491
Georgia	0.483
Hawaii	0.009
Idaho	0.000
Illinois	0.635
Indiana	0.833
Iowa	0.284
Kansas	0.281
Kentucky	0.605
Louisiana	0.236
Maine	0.001
Maryland	0.186
Massachusetts	0.070
Michigan	0.517
Minnesota	0.274
Mississippi	0.114
Missouri	0.545

TABLE 5.—DISTRIBUTION OF STATE BUDGETS—Continued

State	Phase II budget (tons)
Montana	0.148
Nebraska	0.165
Nevada	0.112
New Hampshire	0.025
New Jersey	0.060
New Mexico	0.240
New York	0.157
North Carolina	0.451
North Dakota	0.614
Ohio	0.810
Oklahoma	0.285
Oregon	0.030
Pennsylvania	0.710
Rhode Island	0.000
South Carolina	0.226
South Dakota	0.028
Tennessee	0.378
Texas	1.837
Utah	0.224
Vermont	0.000
Virginia	0.234
Washington	0.077
West Virginia	0.554
Wisconsin	0.353
Wyoming	0.375

Model cap-and-trade program. The EPA is outlining a national cap-and-trade program that States may choose as a cost-effective mechanism to achieve the emissions reductions requirements in today's rulemaking. The trading program will meet these requirements by utilizing a cap on total emissions in order to ensure that emissions reductions under today's proposed rulemaking are achieved, while providing the flexibility and cost effectiveness of a market-based system. This section provides background information and a description of the trading program and an explanation of how the trading program would interface with other State and Federal programs. It is EPA's intent to propose a model rule in a future supplemental notice.

States can voluntarily choose to participate in the trading programs by adopting the model rule, which is a fully approvable control strategy for achieving emissions reductions required under the proposed section 111 rulemaking. Should the States voluntarily choose to participate in the trading program by adopting the model rule, EPA's authority to cooperate with and assist the States in the implementation of the trading program resides in both State law and the CAA. With respect to State law, any State which elects to adopt the model rule as part of its section 111 SIP-like rule will be authorizing EPA to assist the State in implementing the trading program with respect to the sources in that State. With respect to the CAA, EPA believes that the Agency's assistance to those States that choose to participate in the trading program will facilitate the implementation of the program and minimize administrative burden on the States.

Purpose of the trading program and model rule. In the trading program, EPA is proposing to jointly implement with participating States a capped market-based program for certain Utility Units to achieve and maintain an emissions budget consistent with the proposed section 111 rulemaking. Specifically, today's proposal is designed to assist States in: (1) Achieving emissions reductions required under the proposed section 111 rulemaking; (2) ensuring flexibility for regulated sources; (3) reducing compliance costs for sources; and (4) reducing administrative costs to States. In addition to these benefits of electing to participate in the proposed trading program, EPA also seeks to create as simple a regulatory regime as possible by applying a single, comprehensive regulatory approach to all of the affected jurisdictions.

Beyond choosing to use the proposed trading program, State adoption of the model rule would ensure consistency in certain key operational elements of the program among participating States, while allowing each State flexibility in other important program elements. Uniformity of the key operational elements across the participating states would ensure a viable and efficient trading program with low transaction costs and minimum administrative costs for sources, States, and EPA.

Emissions reductions required by the proposed section 111 rulemaking.

State-level emission budgets. Each of the States and the District of Columbia covered by today's proposal has been assigned a statewide emissions budget for Hg. The statewide budgets were developed by totaling unit-level emissions reductions requirements for coal-fired electricity generating devices. The statewide budget development process is fully described elsewhere in today's preamble. States have the flexibility to meet these State budgets by participating in a trading program or requiring source level reductions to coal-fired electric generating units. States have the ability to require reductions beyond those required by the state budget.

Geographic scope of trading program. As discussed elsewhere in this preamble, today's proposal would apply to all coal-fired Utility Units located in all 50 states of the U.S.

Each State has been assigned a statewide emissions budget for Hg. Each of these States must submit a SIP-like plan detailing the controls that will be implemented to meet its specified budget for reductions from electric generating units. Therefore, should some States choose to achieve the mandated reductions by using an approach other than the proposed emissions trading rule, the geographic scope of the trading program would not be nationwide.

Some stakeholders have noted that modeling results suggest that Hg deposition from emissions from Utility Units may be higher in certain regions of the country (*e.g.*, the upper Ohio Valley and Mid-Atlantic areas). In addition, the ecosystems in some regions (*e.g.*, the lakes regions of the Upper Midwest) may be more sensitive to Hg deposition. As discussed more fully below, given the 70 percent emission reduction in the proposed section 111 rule and our experience with cap-and-trade systems, EPA does not expect any local or regional hot spots. The EPA is interested in comments on whether it would be appropriate to adjust the geographic scope of this program to introduce trading ratios between regions as a way of addressing regional differences should they occur. For example, EPA could require that eastern Utility Units in areas of heavy deposition would need greater than 1:1 allowances from Utility Units outside the region to cover an ounce of Hg emissions. The EPA is interested in comments on whether such an approach is appropriate, and if so, on the way to identify appropriate regions where a higher trading ratio would apply and the appropriate magnitude of the trading ratio. The EPA is also interested in comments on the extent to which these adjustments would complicate and reduce the efficiency of the cap-and-trade program.

Affected sources in the trading program. The model trading rule applies to coal-fired Utility Units. The term ''electric utility steam generating unit'' means any fossil fuel fired combustion unit that serves a generator of more than 25 MW that produces electricity for sale. A unit that cogenerates steam and serves a generator that supplies more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale shall be considered an Utility Unit.

Benefits of participating in the trading program. Advantages of cap-and-trade over command-and-control. When designed and implemented properly, a market-based program offers many advantages over its traditional command-and-control counterpart. *See* discussion, *supra,* Section III. Six principal advantages of market-based systems have been recognized: (1) Results in a certain, fixed cap in emissions from affected and potentially affected sources; (2) potential for the creation of incentives for early reductions; (3) creation of incentives for emissions reductions beyond those required by regulations; (4) reduced cost of compliance for individual sources and the regulated community in general; (5) promotion of innovation and continued evolution of production and pollution control technology; and, (6) increased flexibility for the regulated community without resorting to waivers, exemptions and other forms of administrative relief. These benefits result primarily from the flexibility in compliance options available to sources and the monetary reward associated with avoided emissions in a market-based system. The cost of compliance in a market-based program is reduced because sources have the freedom to pursue various compliance strategies, such as switching fuels, installing pollution control technologies, or buying authorizations to emit from a source that has over-complied. Since emissions level below the level mandated allows the freeing up of allowances that may be sold on the market, pollution prevention becomes more cost effective, and innovations in less-polluting alternatives and control equipment are encouraged.

A market system that employs a fixed tonnage limitation (or cap) for a source or group of sources provides the greatest certainty that a specific level of emissions will be attained and maintained since a predetermined level of reductions is ensured. With respect to transport of pollution, an emissions cap also provides the greatest assurance to downwind States that emissions from upwind States will be effectively managed over time. The capping of total emissions of pollutants over a region and through time ensures achievement of the environmental goal while allowing economic growth through the development of new sources or increased use of existing sources. In an uncapped system (where, for example, sources are required only to demonstrate that they meet a given emission rate) the addition of new sources to the regulated sector or an increase in activity at existing sources can increase total emissions even though the desired emission rate control is in effect.

In addition, the reduced implementation burden for regulators and affected sources benefits taxpayers and those who must comply with the rules. This streamlined administrative approach allows a small number of government employees to successfully regulate many sources by (1) minimizing the necessity for case-by-case rules and (2) taking full advantage of electronic communication and data transfer to track compliance and develop detailed, critical inventories of emissions and plant operations.

Application of the cap-and-trade approach in prior rulemakings. Title IV. Title IV of the 1990 Amendments to the CAA established the Acid Rain Program, a program that utilizes a market-based cap-and-trade approach to require power plants to reduce SO_2 emissions by 50 percent from 1980 levels by 2010. At full implementation after 2010, emissions will be limited, or capped, at 8.95 million tons. It also includes emission rate requirements to reduce NO_X emissions. The Acid Rain Program for SO_2 is widely acknowledged as a model air pollution control program because it provides significant and measurable environmental and human health benefits with low implementation costs.

Units are allocated their share of the total allowances, each allowance providing an authorization to emit a ton of SO_2, based upon historical records of the heat content of the fuel that they combusted during the period 1985 to 1987. Units that reduce their emissions below the number of allowances they hold may trade allowances with other units in their system, sell them to other sources on the open market or through EPA auctions, or bank them to cover emissions in future years. Each affected unit is required to surrender allowances to cover its emissions each year. Should any unit fail to hold sufficient allowances, automatic penalties apply. In addition to financial penalties, units either will have allowances deducted immediately from their accounts to offset their allowance deficiencies or, if such deduction would threaten electric reliability, may submit a plan to EPA that specifies when the allowances will be deducted in the future.

An essential feature of the Acid Rain Program is the requirement for affected sources to install systems that continuously monitor emissions. The use of CEMS was an important innovation that allowed both EPA and sources to track progress, ensure compliance, and provide credibility to the trading component of the program.

While title IV does provide for an Acid Rain Permit, the permit simply states a non-source specific requirement that sources comply with the standard

rules of the program. Acid Rain permitting has been easily incorporated into the title V permit process and does not require the typically resource intensive, case-by-case review associated with other permits under command-and-control programs.

The Acid Rain Program has achieved major SO_2 emissions reductions, and associated air quality improvements, quickly and cost-effectively. In 2002, SO_2 emissions from power plants were 10.2 million tons, 41 percent lower than 1980. True to its intent, the program has substantially reduced acid deposition, allowing lakes and streams in the Northeast to begin recovering from decades of acid rain. The Acid Rain Program resulted in emission reductions well below the cap in the areas that contribute most of the sulfur in the acid rain. Comparing emissions from the 263 power plants regulated in the first phase of the program in 1999 with those in 1990, the North Central and Southeast and Mid-Atlantic regions achieved 49 percent, 48 percent and 43 percent reductions in SO_2, respectively. Several analyses of trading under the acid rain program have concluded that the program did not result in local areas with ''hot spots.''

Trading under the Acid Rain Program has created financial incentives for electricity generators to look for new and low-cost ways to reduce emissions, and improve the effectiveness of pollution control equipment, at costs much lower than predicted. In fact, the Acid Rain Program achieved reductions at two-thirds the cost of achieving the same reductions under a command-and-control system. The cap on emissions and significant automatic penalties for noncompliance ensure that environmental goals are achieved and sustained, while stringent emissions monitoring and reporting requirements make flexibility possible. The level of compliance under the Acid Rain Program continues to be uncommonly high, measuring over 99 percent.

NO_X SIP call and OTC Trading Program. The cap-and-trade approach has also been used to address regional ozone transport problems in the eastern U.S. The north-eastern states (Ozone Transport Commission) began implementing a cap-and-trade program to address regional ozone transport in 1999. The NO_X Budget Trading Program under the NO_X SIP Call began its first year of implementation in 2003 in the Northeast. Eleven additional States will join in 2004. Each of the States required to submit a NO_X SIP to address the regional transport of ozone chose to participate in the interstate trading program. They each based their trading program on the model rule; some states essentially adopted it in full, other states modified some provisions for their unique circumstances.

Local environmental improvements achieved using cap-and-trade model. Mercury emissions from power plants sometimes are deposited locally near the plant. Nearby lakes may be a source of fish consumption for recreational and/or subsistence fisherman, and thus local Hg deposition in nearby lakes could be a source of what are called hot spots. In this discussion, we are assuming that a power plant may lead to a hot spot if the contribution of the plant's emissions of Hg to local deposition is sufficient to cause blood Hg levels of highly exposed individuals near the plant to exceed the RfD. For the purposes of choosing a regulatory tool to address hot spots, the relevant question is what is the contribution of these plants to hot spots under a cap-and-trade approach, relative to their current contribution and their projected contribution under a traditional section 112 approach.

Concerns about hot spots have been raised despite the success and growing use of cap-and-trade programs. The EPA believes that a trading approach will help to address this problem. In addition to reductions required by the cap, all States would have the ability to address local health-based concerns separate from the Hg cap-and-trade program requirements.

The EPA does not anticipate significant local health-based concerns under a national Hg trading program. The Agency has considered this possibility and believes that the cap-and-trade system, coupled with related Federal and State programs, will effectively address local risks. This has been EPA's experience with the title IV program limiting SO_2 emissions.

First, modeling runs suggest that large coal-fired Utility Units—those that tend to have relatively high Hg emissions—are likely to have larger local deposition footprints than medium-sized and smaller coal-fired Utility Units. However, the trading of allowances is likely to involve large Utility Units controlling their emissions more than required and selling allowances to smaller Utility Units rather than the reverse scenario. This prediction arises from the basic economics of capital investment in the utility industry. Under a trading system where the firm's access to capital is limited, where the up-front capital costs of control equipment are significant, and where emission-removal effectiveness (measured in percentage of removal) is unrelated to plant size, it makes more economic sense for the utility company to allocate pollution-prevention capital to its larger facilities than to the smaller plants (since more allowances will be earned). Any economies of scale of pollution control investment will favor investment at the larger plants. Insofar as large coal-fired Utility Units tend to be newer and/or better maintained than medium-sized and small facilities, it can be expected that companies will favor investments in plants with a longer expected lifetime.

Second, the types of Hg that are deposited locally—Hg^{++} and particulate Hg (Hg_p)—are controlled by the same equipment that controls criteria air pollutants (fine particles, SO_2 and NO_X). These same types of Hg are more likely to be deposited locally than Hg^0. As utilities invest in equipment to comply with the Agency's new fine particle and ozone control regulations (*e.g.*, today's proposed IAQR, and new State Implementation Plans (SIP) for fine particles and ozone), the Agency expects a ''co-benefit'' in Hg control as controls such as particulate controls, scrubbers and SCR units are installed on an increasing percentage of coal-fired Utility Units. The type of Hg that is most difficult to control is Hg^0, and it is this gaseous form of Hg that is most likely to be transported long distances from the Utility Units. Effective control of Hg^0 may require significant investment in Hg-specific control technologies that are only beginning to reach the commercialization stage.

Considering the economies of Hg trading, Utility Units that have significant emissions of Hg^0 may become buyers of allowances from plants that can cost-effectively control Hg^{++} and Hg_p. Consequently, the economics of the trading system are likely to favor controls of Hg that are likely to be deposited locally, thereby reducing any local hot spots.

The structure of the proposed rule permits States to adopt more stringent performance standards if the State determines that such regulations are necessary. Although more stringent State regulations will reduce flexibility built into the cap-and-trade system, States retain the power under the proposed section 111 rule to adopt stricter regulations to address local hot spots or other problems. Given the 70 percent emission reduction in the proposed section 111 rule and our experience with cap-and-trade systems, which shows that the largest emitters are the first to install stringent emission controls, we do not expect any local or regional hot spots. However, the Agency plans to continue monitoring Hg emissions and the operation of the

trading system to make sure that localized hot spots do not materialize.

As part of its analysis of the President's Clear Skies initiative, EPA analyzed Hg emissions reductions under a cap-and-trade mechanism. In the Clear Skies example, the greatest emissions reductions were projected to occur at the electric generating sources with the highest Hg emissions. This pattern is similar to that observed in the SO_2 emissions trading program under the Acid Rain Program. Under Clear Skies, compared to a base case of existing programs, ionic Hg emissions (those Hg emissions which tend to be deposited locally, *i.e.*, within 25 kilometers) from power plants located up to 10 kilometers from a water body were projected to decrease by over 60 percent in 2020. In addition, based on regional-scale Hg deposition model predictions, Clear Skies could reduce Hg deposition by 5 to 15 percent beyond the existing program base case across much of the eastern U.S. and could do so to higher levels in certain specific locations. Based on this available information, the proposed cap-and-trade mechanism in this regulatory proposal can be expected to reduce Hg deposition similarly in most areas. Consequently, the EPA does not anticipate significant local health-based concerns under a national Hg trading program.

We explain elsewhere in this proposal our intention to take a hard look at the Hg emissions inventory after full implementation of the first phase cap. The main purpose of this review is to determine whether the actual reductions achieved under this program significantly differ from the outcome predicted by our current analysis. We retain authority to make adjustments to the program if we find remaining areas with heavy, localized emissions and higher health risks (*i.e.*, if we find ''hot spots'').

In the final days before signature and publication of this proposal, concerns about the possibility of ''hot spots'' under our proposed cap and trade program were widely reported. We agree that this is an important issue and believe that our program will effectively address potential ''hot spots.'' We ask for comment on this issue. We are particularly interested in receiving site-specific data and information about locations where commenters believe ''hot spots'' will continue to exist after implementation of these rules.

State adoption of the model rule. Participation in the trading program would enable States that have been identified in the proposed section 111 rulemaking to achieve the required emissions reductions from stationary combustion sources while minimizing the administrative burden faced by both States and sources. The SIP-like rule process required by the proposed rulemaking would be significantly streamlined for States choosing to include the trading program as a part of the SIP-like rule. The EPA proposes that adoption of the model rule, to be published in a future supplemental notice of proposed rulemaking (SNPR), will be considered a SIP-approvable control strategy for the proposed section 111 rulemaking. States electing to participate in the trading program may either adopt the model rule by reference or develop State regulations that are in accordance with the model rule.

The permitting process under the trading program would be significantly streamlined since there will be no need for enforceable compliance plans and source-specific requirements (each permit will have to be revised to add Hg trading program requirements). Emissions monitoring, a central requirement of the trading program, as well as the availability to the public of emissions data, allowance data, and annual reconciliation information, would ensure that participating States and the public have confidence that the required emissions reductions are being achieved.

States that elect to participate in the trading program, thereby allowing sources to seek the least-cost reductions, are expected to see substantially lower compliance costs for their sources than under a comparable rate based program.

Sources included in the trading program also benefit from increased compliance flexibility, as compared to a rate-based approach that requires each affected source to comply with an emission rate and necessitates installation of control equipment for any affected source that cannot meet the limit. Participation in the trading program provides sources the choice of numerous compliance strategies. Moreover, sources can choose to over-comply and free up excess allowances that can be sold on the market or, as discussed below, possibly banked for future use. In addition, sources may change their control approach at any time without regulatory agency approval.

The Hg trading program. Brief description of Hg trading program. The trading program establishes a first phase cap at a level that reflects the Hg reductions expected with the SO_2 and NO_x in the IAQR in 2010 and a Phase II cap of 15 tons on Hg emissions for affected Utility Units starting in 2018. The new trading program for Hg would require sources to hold allowances covering emissions beginning January 1, 2010. The EPA is proposing that the owner or operator must hold allowances for all the affected Utility Units at a facility at least equal to the total Hg emissions for those units during the year. Compliance with the requirement to hold allowances will thus be determined on a facility-wide basis. In a supplemental notice entitled ''Emission Guidelines and Compliance Times for Coal-fired Electric Utility Steam Generating Units'' EPA will be proposing unit allocations for existing units. New units will be covered under the Hg cap of the trading program and will be required to hold allowances. In the SNPR, EPA will recommend options for States to address the inclusion of new sources (*e.g.*, new source set asides and/or updating allocations).

Applicability. The model trading rule applies to coal-fired combustion units serving a generator of more than 25 MW that produces electricity for sale. A unit that cogenerates steam and supplies more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale shall be considered an Utility Unit.

State trading budgets. This proposal establishes the total number of tons for the Budget Trading Program within a specific State. The proposed rule sets the State's unit level allocations and adds up those allocations to develop a State level budget.

In a supplemental notice entitled ''Emission Guidelines and Compliance Times for Coal-fired Electric Utility Steam Generating Units,'' EPA will be taking comment on the proposed methodology for establishing unit level allocations and the data used to develop these allocations. As discussed earlier, unit allocations were determined by adjusting a baseline heat input. That baseline heat input was determined using the average of the three highest heat inputs of the period 1998 to 2002. In order to adjust the heat input based on coal type, coal usage patterns were determined from the ICR data. The EPA requests comment on the data used to develop proposed unit-level allocation. The EPA also requests comment on the appropriateness of using 1999 data to determine the coal adjustment factors.

In today's proposal, EPA is proposing a safety valve provision that sets a maximum cost for Hg emissions reductions. This provision addresses some of the uncertainty associated with the cost of Hg control. In fact, there is an ongoing research process sponsored by EPA, the DOE, the Electric Power Research Institute (EPRI), and vendors specifically aimed at furthering our

understanding of Hg control, with new data being made available on a continuous basis.

Under the safety valve mechanism, the price of allowances is capped, meaning that if the allowance price exceeds the ''safety-valve,'' sources may borrow allowances from following years to have access to more allowances available at that price. The EPA proposes a price of $2,187.50 for a Hg allowance (covering one ounce). This price will be annually adjusted for inflation. The Administrator will deduct corresponding allowances from future facility allowance accounts.

The purpose of this provision is to minimize unanticipated market volatility and provide more market information that industry can rely upon for compliance decisions. The safety valve mechanism ensures the cost of control does not exceed a certain level, but also ensures that emissions reductions are achieved. The future year cap is reduced by the borrowed amount, and the emissions reductions are achieved.

We note that this proposed approach may create implementation problems associated with the need to ''reconcile'' at some point in time the allowances borrowed from future compliance periods. We ask for comment on the need for a safety valve and the viability of our proposed approach, and solicit suggestions for other viable approaches.

We also ask for comment on the possibility of conducting auctions each year, at which allowances would be offered for sale. The pool of allowances to be auctioned would be created by specified procedures, such as setting aside a fixed or incremented percentage of allocations each year. The auctions would be open to any person. A person wishing to bid for allowances in the auction would submit bids according to auction procedures, a bidding schedule, a bidding means, and requirements for financial guarantees specified in the regulations. Winning bids, and required payments, for allowances would be determined in accordance with the regulations. For any winning bid, we would record the allowances in a tracking system only after the required payment for such allowances is received. If we decide to provide for auctions, we would need to determine how to collect and properly disperse the revenues. We believe that responsibility for managing this aspect of the program would necessarily fall to the individual states that opt to participate in the cap and trade program. We ask for comment on all aspects of this auctions proposal. If we decide to proceed, details of the auction program would be spelled out in the upcoming SNPR.

Key elements of Hg model cap-and-trade rule to be proposed in SNPR. Allowance allocations. The EPA is proposing heat input-based allocations for existing coal units (with different ratios for different coal types).

The EPA believes that allocating based on heat input data is desirable because accurate protocols exist for monitoring this data and reporting it to EPA, and several years of certified data are available for most of the affected sources.

New sources will be covered under the Hg cap of the trading program and will be required to hold allowances equivalent to the product of their NSPS standard and a baseline heat input. Therefore, state budgets will be maintained at the levels proposed in today's rulemaking even after the addition of new coal-fired electricity generating units in the state. State SIP-like rules will need to address the inclusion of these new sources in their state budget. In the SNPR, EPA will recommend options for states to address the inclusion of new sources (*e.g.*, new source set asides and/or updating allocations).

Allowance management system, compliance, penalties, and banking. Each of these elements is part of the accounting system that enables the functioning of a trading program. An accurate, efficient accounting system is critical to an emissions trading market. Transparency of the system, allowing all interested parties access to the information contained in the accounting system, increases the accountability of regulated sources and contributes to reduced transaction costs of trading allowances.

In order to guarantee the equitable treatment of all affected sources across the trading region, the elements included in this section need to be incorporated in the same manner in each state that participates in trading.

Allowance management. The EPA intends to propose a model trading rule that will be reasonably consistent with the existing allowance tracking systems that are currently in use for the Acid Rain Program under title IV and the NO_X Budget Trading Program under the NO_X SIP Call. These two systems are called the Allowance Tracking System (ATS) and the NO_X Allowance Tracking System (NATS), respectively. Under the section 111 trading rule, EPA would maintain a separate system for Hg, Mercury Allowance Tracking System (MATS). The MATS would be established as an automated system used to track Hg allowances held by affected units under the Hg cap-and-trade program, as well as those allowances held by other organizations or individuals. Specifically, MATS would track the allocation of all Hg allowances, holdings of Hg allowances in accounts, deduction of Hg allowances for compliance purposes, and transfers between accounts. The primary role of MATS, in conjunction with an emissions tracking system, is to provide an efficient, automated means of monitoring compliance with the trading programs. The MATS also provide the allowance market with a record of ownership of allowances, dates of allowance transfers, buyer and seller information, and the serial numbers of allowances transferred.

Compliance. Compliance in the trading program consists of the deduction of allowances from affected facilities'' accounts to offset the quantity of emissions at the facilities. The EPA plans to propose that compliance be assessed at the facility level, rather than the unit level as is currently done in both the Acid Rain and NO_X Budget trading programs.

Penalties. The EPA plans to propose a system of automatic penalties should a facility not obtain sufficient Hg allowances to offset emissions for the compliance period. The automatic penalty provisions will not limit the ability of the permitting authority or EPA to take enforcement action under State law or the CAA.

Banking. Banking is the retention of unused allowances from 1 year for use in a later calendar year. Banking allows sources to create reductions beyond required levels and ''bank'' the unused allowances for use later. Generally speaking, banking has several advantages: it can encourage earlier or greater reductions than are required from sources, stimulate the market and encourage efficiency, and provide flexibility in achieving emissions reduction goals. On the other hand, it may result in banked allowances being used to allow emissions in a given year to exceed the trading program budget. The EPA plans to propose that banking of allowances after the start of the Hg trading program be allowed with no restrictions.

Emissions monitoring and reporting. Monitoring and reporting are an integral part of any cap-and-trade program. Consistent and accurate quantification of emissions ensures each allowance actually represents one ounce of emissions and that one ounce of reported emissions from one source is equivalent to one ounce of reported emissions from another source. This establishes the integrity of the

allowance (*i.e.*, the authorization to emit one ounce of Hg) and instills confidence in the market mechanisms that are designed to provide sources with flexibility in achieving compliance. Given the variability in the type, operation and fuel mix of sources in the cap-and-trade program, EPA believes that to ensure this accuracy and consistency, emissions must be monitored using continuous emissions monitoring methods. As discussed earlier, EPA plans to include in the model trading rule a requirement for States to require year-round Part 75 monitoring and reporting for all sources.

Accountability for affected sources. Key to the success of existing cap-and-trade programs and the integrity of the emission allowance trading markets has been clear accountability for a source's emissions. This takes the form of affected sources officially designating a specific person (and alternate) that is responsible for the official certification of all allowance transfers and emissions monitoring and reporting as submitted to EPA in quarterly compliance reports. With each quarterly submission, this responsible party must certify that: (1) the monitoring equipment data were reported in compliance with the monitoring and reporting requirements, and (2) the emission and operation reports are true, accurate, and complete.

The trading program to be proposed in the future SNPR will include provisions to provide for the same strict standards for source accountability established in the Acid Rain Program and the NO_X SIP call. This will include provisions for the establishment and management of an Authorized Account Representative. Adoption of these provisions will be required by all States that wish to participate in the trading program.

3. What Are the Subpart Da Hg Emission Guidelines?

This information will be provided in the Emission Guidelines, which will be provided in an upcoming supplemental notice.

4. How Did EPA Select the Format for the Proposed Emission Guidelines?

This information will be provided in the Emission Guidelines, which will be provided in an upcoming supplemental notice.

5. How Did EPA Determine the Emissions Monitoring and Reporting Requirements for the Proposed Emission Guidelines?

Monitoring and reporting are an integral part of any Hg reduction program, including a cap-and-trade program. Consistent and accurate quantification of emissions ensures the integrity of a Hg reduction program. The continuous emissions monitoring methods must incorporate rigorous quality assurance testing and substitute data provisions for times when monitors are unavailable because of planned and unplanned outages. In addition, there must be requirements for record keeping and electronic reporting. Provisions like these are contained in 40 CFR part 75, and are used in both the Acid Rain and NO_X SIP Call programs, for SO_2 and NO_X, but not currently for Hg.

In an effort to maintain program integrity, the EPA plans to propose revisions to 40 CFR part 75 to establish requirements for emission monitoring, quality assurance, substitute data, record keeping, and reporting and to include in the SNPR a requirement for States to require year-round Part 75 monitoring and reporting for all sources. Monitor certification deadlines and other details will be specified in the SNPR. The EPA believes that emissions will then be consistently and accurately monitored and reported from unit to unit and from State to State.

The EPA also intends to require year-round reporting of emissions and monitoring data from each unit at each affected facility. A single report for Hg will be required on a quarterly basis in a format specified by the EPA. The reports will be required to be in an electronic data reporting (EDR) format and must be submitted to EPA electronically. The reports will be maintained in EPA's Emissions Tracking System (ETS). This centralized reporting requirement is necessary to ensure consistent review, checking, and posting of the emissions and monitoring data at all affected sources, which contributes to the integrity of the Hg reduction program.

6. How Did EPA Determine the Compliance Times for the Proposed Emission Guidelines?

This information will be provided in the Emission Guidelines, which will be provided in an upcoming supplemental notice.

E. Rationale for the Proposed Ni Guidelines

1. What Is the Rationale for the Proposed Subpart Da Ni Emission Guidelines?

The proposed emission guidelines for Ni from existing oil-fired units was determined by analyzing the emissions data available. The data were obtained from the Utility RTC which provided information indicating that Ni was the pollutant of concern due to its high level of emissions from oil-fired units and the potential health effects arising from exposure to it. The EPA examined available test data and found that ESP-equipped units can effectively reduce Ni. Analysis of the available emissions data indicated that existing oil-fired units can limit Ni emissions to 210 lb/TBtu input or 0.002 lb/MWh output gross. The EPA is proposing both an input-based and an output-based standard in the proposed rule for existing sources (based on potential difficulties in retrofitting the necessary data acquisition measures for the output-based standard at an existing source).

The EPA is sensitive to the fact that some sources burn fuels containing very little Ni. Therefore, EPA solicits comment on a Ni-in-oil limit that would be equivalent to the proposed stack values of 210 lb/TBtu input or 0.002 lb/MWh gross. With a limit on the amount of Ni in the oil, an existing source could choose to comply with an alternate oil-content-based Ni emission limitation instead of the stack Ni emission limit to meet the proposed rule. Such an alternate Ni-in-oil limit could be useful where Ni constituent levels are low in the fuel.

Two alternatives for compliance purposes are provided in the proposed rule for oil-fired units. The owner/operator can elect to: (1) Meet the standard of performance for Ni, or (2) burn distillate oil (exclusively) rather than residual oil. If an oil-fired unit is currently burning, or switches to burning, distillate oil (exclusively), it would be exempt from all oil-fired unit initial and continuous compliance requirements until such time as it begins burning any oil other than distillate oil. The proposed rule would require that the exempted oil-fired unit begin the performance testing procedures if it resumes burning a fuel other than distillate oil.

2. How Did EPA Address Dual-Fired (Oil/Natural Gas) Units?

The EPA is aware that an oil-fired unit may fire oil at certain times of the year and natural gas at other times. The choice of when to fire oil or natural gas is usually based on the economics or availability of fuel (*i.e.,* seasonal considerations). As stated elsewhere in this preamble, EPA considers a unit to be an oil-fired unit if (1) it is equipped to fire oil and/or natural gas, and (2) it fires oil in amounts greater than or equal to two percent of its annual fuel consumption. This two percent value is intended to represent that amount of oil that a true natural gas-fired unit might

use strictly for start-up purposes on an annual basis. The EPA solicits comment on whether this two percent breakpoint is a reasonable basis for allowing those units that use oil only for startup purposes to be exempted from regulation under the proposed rule.

V. Impacts of the Proposed Rule

Under the section 111 proposed approach, Hg reductions prior to 2015 are expected to be comparable to Hg reductions achieved under the proposed section 112 MACT. In fact, given the early reductions achieved from banking under the section 111 proposal, plus the possibility that a section 112 MACT approach provides no incentive for power plants to reduce below the required level, a section 111 approach will likely lead to greater reductions in the Hg relative to the proposed section 112 MACT approach. After 2015, the Phase II cap in the proposed section 111 approach is reduced to 15 tpy, leading to still more reductions than achieved under the proposed section 112 MACT. Therefore, the estimated benefits of the proposed section 112 MACT can serve as a lower bound of the benefits achieved through the proposed section 111 approach.

A. What Are the Air Impacts?

When the emissions rates developed in today's proposed section 112 MACT rule are applied to current coal use (based on the ICR), annual Hg emissions to the atmosphere from Utility Units are projected to be 34 tons. Consistent with previous regulatory programs affecting electricity generating units, EPA has analyzed this scenario using the Integrated Planning Model (IPM) (*see http://www.epa.gov/airmarkets/epa-ipm*). Based on this model, total Hg emissions from affected coal-fired power plants are projected to be 30 tons in 2010 and 31 tons in 2020. However, Hg emissions are likely to be much closer to the calculated level of 34 tons. First, the model allows for Hg reductions using ACI only at the 60 percent and 90 percent levels (rather than using a range of 60 to 90 percent), which may lead the model to understate Hg emissions from as much as 2.3 tons by bituminous-fired units. Second, the modeling may not fully capture the range of Hg in different coal ranks which could underestimate emissions, particularly when modeling a facility-specific limit as is the case with this analysis. The modeling assumes a range of Hg contents for different ranks of coal, but due to averaging, may not fully capture all Hg contents of coal. (*See* IPM documentation, Chapter 4 for further information on Hg content of coal.)

B. What Are the Water and Solid Waste Impacts?

The EPA estimated the additional water usage that would result from the MACT floor level of control to be 307 million gallons per year for existing affected sources. These costs are accounted for in the control costs estimates.

The EPA estimated the additional solid waste that would result from the MACT floor level of control to be 282,000 tpy for existing sources. The costs of handling the additional solid waste generated are also accounted for in the control costs estimates.

A discussion of the methodology used to estimate impacts is presented in the memorandum entitled ''Methodology for Estimating Cost and Emissions Impact for Coal- and Oil-Fired Electric Utility Steam Generating Units National Emission Standards for Hazardous Air Pollutants'' in the docket.

C. What Are the Energy Impacts?

The EPA expects an increase of approximately 1,418 million kilowatt hours (kWh) in national annual energy usage as a result of the proposed rule. The increase results from the electricity required by existing sources to operate control devices installed to meet the proposed rule.

D. What Are the Control Costs?

Table 6 of this preamble shows the estimated capital and annual cost impacts for each subcategory. Costs include testing and monitoring costs, but not record keeping and reporting costs.

TABLE 6.—SUMMARY OF CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES UNDER THE SECTION 112 MACT PROPOSAL

Source	Subcategory	Estimated/projected No. of affected units	Annualized cost (10^6\$/yr)	Capital costs (10^6\$)
Coal-fired Units	Bituminous-fired	549	728	4,609
	Subbituminous-fired	68	92	607
	Lignite-fired	5	9	61
	Blends	74	101	654
	IGCC unit	0	0	0
	Coal refuse-fired	3	16	52
Total, coal-fired units		719	945	5,982
Oil-fired Units	Oil-fired	186	417	2,190
Total, coal- and oil-fired units		905	1,362	8,172

Costs are estimated from methods based on the ''EPA Air Pollution Control Cost Manual,'' which uses a factor method for estimating total capital investment, then total annual and annualized costs for an emission control system. Basic equipment costs are found either from the Manual or from vendor contacts. Factors in the manual are applied to the equipment cost to estimate direct and indirect costs associated with installing the equipment. Annual operating and maintenance costs and annualized costs for debt service are estimated to obtain annual payments attributable to the system used for emission control. For electric utility costing, each of the U.S. units is costed separately using equations developed from the cost manual. A discussion of the methodology used to estimate impacts is presented in the memorandum entitled ''Methodology for Estimating Cost and Emissions Impact for Coal- and Oil-Fired Electric Utility Steam Generating Units National Emission Standards for Hazardous Air Pollutants'' in the docket.

As part of the costing, annual quantities of water, wastewater, solid waste, and energy required for operating the emission control systems are determined. These quantities represent materials or energy used in the system or wastes that must be treated as a result of system operation. The quantities are listed elsewhere in this preamble.

E. Can We Achieve the Goals of the Proposed Section 112 MACT Rule in a Less Costly Manner?

The EPA has tried in developing the section 112 MACT proposal to ensure that the cost to the regulated community is reasonable in view of the potential benefits, and to allow maximum flexibility in compliance options consistent with our statutory obligations. The Agency recognizes, however, that the section 112 MACT proposal may still require some facilities to take costly steps to further control Hg and Ni emissions even though those emissions may not result in exposures which could pose unacceptable risk. The EPA is, therefore, specifically soliciting comment on whether there are further ways to structure the section 112 MACT proposal to focus on the facilities which may pose significant risks to public health and avoid the imposition of high costs on facilities that pose little risk to public health and the environment.

F. What Are the Social Costs and Benefits of the Proposed Section 112 MACT Rule?

The proposed rule sets out two major alternative actions. The first alternative would regulate Hg emissions under the section 112 MACT provisions CAA. The second alternative would regulate Hg emissions through a cap-and-trade program under section 111 of the CAA. Implementation of the section 111 cap-and-trade program would be carried out in coordination with a cap-and-trade program for SO_2 and NO_X emissions under the IAQR, which is also being proposed in today's **Federal Register.** The IAQR would limit Utility Unit SO_2 and NO_X emissions in approximately 30 eastern states to address their contribution to nonattainment of the fine particle ($PM_{2.5}$) and ozone National Ambient Air Quality Standards (NAAQS).

The control approaches adopted by Utility Units in response to the proposed section 112 Hg MACT regulations would also achieve collateral reductions of NO_X and SO_2. Based on the scenario analyzed, the proposed action would reduce approximately 902,000 tons of NO_X emissions, and 591,000 tons of SO_2 emissions in 2010. The proposed IAQR would require annual SO_2 emissions reductions of 3.6 million tons and NO_X emissions reductions of 1.4 million tons in 2010, while achieving Hg reductions comparable to those estimated for the proposed section 112 MACT by 2010.

Our assessment of costs and benefits of the proposed MACT rule is detailed in the ''Benefits Analysis for the Section 112 Utility Rule,'' located in the Docket. These analyses are based on the costs and emissions reductions associated with a particular Hg control scenario that is consistent with the reduction in nationwide Hg emissions expected by implementation of the proposed section 112 MACT standard. The specific emissions control scenario is derived from application of the Integrated Planning Model (IPM), which EPA has used to assess the costs and emissions reductions associated with a number of regulations of the power sector. While the Hg reduction estimates in the scenario are consistent with the Agency's assessment of control technologies, EPA is aware that estimates of associated reductions in other pollutants, notably SO_2 and NO_X (co-benefits) may vary significantly with alternative assumptions about the application of particular control technologies and incentives created by the existence of other major regulatory programs affecting the power sector. In particular, based on past EPA analyses of multi-pollutant strategies (*e.g.* Clear Skies Technical Support Document D, *http://www.epa.gov/clearskies/technical.html)* the control choices made pursuant to either a 111-or 112-based Hg program would likely be significantly affected by the requirements of the IAQR. For these reasons, in addition to the findings of the analyses derived from the MACT-only scenario, we also provide some estimates of the direction of costs and benefits under reasonably foreseeable alternative scenarios for implementing limits on Hg emissions that take such potential interactions into account.

The proposed section 111 and 112 actions address Hg and Ni emissions from coal- and oil-fired Utility Units. Exposure to emissions of Hg at low levels may cause neurological damage and learning disorders. Nickel subsulfide and refinery dusts are classified as known human carcinogens; Ni carbonyl is classified as a probable human carcinogen based upon studies in animals. Due to the control technologies selected for analysis, the actions to reduce Hg will also achieve reductions of NO_X and SO_2. Although not incorporated into the analyses, the actions to reduce Ni will also reduce direct emissions of particulate matter. Known health and welfare effects associated with the pollutants affected by the proposed rule are listed in Table 7 of this preamble. As indicated in the table, we are able to quantify and monetize only a portion of these effects.

TABLE 7.—HEALTH AND WELFARE EFFECTS OF POLLUTANTS AFFECTED BY THE PROPOSED UTILITY MACT STANDARD

Pollutant/effect	Quantified and monetized	Unquantified effects
PM/Health	Premature mortality—adults	Low birth weight.
	Premature mortality—infants	Changes in pulmonary function.
	Bronchitis—chronic and acute	Chronic respiratory diseases other than chronic bronchitis.
	Hospital admissions—respiratory and cardiovascular	Morphological changes.
	Emergency room visits for asthma	Altered host defense mechanisms.
	Non-fatal heart attacks (myocardial infarction)	Non-asthma respiratory emergency room visits.
	Lower and upper respiratory illness	Changes in cardiac function (*e.g.,* heart rate variability).
	Asthma exacerbations	Allergic responses (to diesel exhaust).
	Minor restricted activity days	
	Work loss days	
PM/Welfare		Visibility in Class I areas.
		Visibility in residential and non-Class I areas.
		Household soiling.
Ozone/Health		Increased airway responsiveness to stimuli.
		Inflammation in the lung.
		Chronic respiratory damage.
		Premature aging of the lungs.

TABLE 7.—HEALTH AND WELFARE EFFECTS OF POLLUTANTS AFFECTED BY THE PROPOSED UTILITY MACT STANDARD—Continued

Pollutant/effect	Quantified and monetized	Unquantified effects
		Acute inflammation and respiratory cell damage.
		Increased susceptibility to respiratory infection.
		Non-asthma respiratory emergency room visits.
		Hospital admissions—respiratory.
		Emergency room visits for asthma.
		Minor restricted activity days.
		School loss days.
		Asthma attacks.
		Cardiovascular emergency room visits.
		Premature mortality B acute exposures.
		Acute respiratory symptoms.
Ozone/Welfare		Decreased commercial forest productivity.
		Decreased yields for fruits and vegetables.
		Decreased yields for commercial and non-commercial crops.
		Damage to urban ornamental plants.
		Impacts on recreational demand from damaged forest aesthetics.
		Damage to ecosystem functions.
		Decreased outdoor worker productivity.
Nitrogen and Sulfate Deposition/Welfare.		Costs of nitrogen controls to reduce eutrophication in selected eastern estuaries.
		Impacts of acidic sulfate and nitrate deposition on commercial forests.
		Impacts of acidic deposition on commercial freshwater fishing.
		Impacts of acidic deposition on recreation in terrestrial ecosystems.
		Impacts of nitrogen deposition on commercial fishing, agriculture, and forests.
		Impacts of nitrogen deposition on recreation in estuarine ecosystems.
		Reduced existence values for currently healthy ecosystems.
SO_2/Health		Hospital admissions for respiratory and cardiac diseases.
		Respiratory symptoms in asthmatics.
NO_X/Health		Lung irritation.
		Lowered resistance to respiratory infection.
		Hospital Admissions for respiratory and cardiac diseases.
Hg Health		Neurological disorders.
		Learning disabilities.
		Developmental delays.
		Cardiovascular effects*.
		Altered blood pressure regulation*.
		Increased heart rate variability*.
		Myocardial infarctions*.
		Reproductive effects in adults*.
Hg Deposition Welfare		Impacts on birds and mammals (*e.g.* reproductive effects).
		Impacts to commercial, subsistence, and recreational fishing.
		Reduced existence values for currently healthy ecosystems.
Ni Health		Dermatitis.
		Respiratory effects.
		Increased Risk of Lung and Nasal cancer.

* These are potential effects as the literature is either contradictory or incomplete.

It is estimated that the section 112 MACT proposal will reduce national Hg emissions to approximately 34 tons and national Ni emissions to approximately 103 tons at electric utility facilities that generate steam using fossil fuels (*i.e.*, coal or oil fuels). The health effects associated with these pollutants are discussed earlier in this preamble, however, a summary of the potential benefits is provided below. While it is beneficial to society to reduce Hg and Ni, we are unable to quantify and provide a monetized estimate of the benefits at this time due to gaps in available information on the fate of emissions for these two pollutants, human exposure, and health impact models.

The Hg and Ni emissions reductions associated with implementing of the proposed action would produce a

variety of benefits. Mercury emitted from utilities and other natural and man-made sources is carried by winds through the air and eventually is deposited to water and land. In water, Hg is transformed to methylmercury through biological processes. Methylmercury, a highly toxic form of Hg, is the form of Hg of greatest concern for the purpose of this rulemaking. Once Hg has been transformed into methylmercury, it can be ingested by the lower trophic level organisms where it can bioaccumulate in fish tissue (*i.e.*, concentrations in predatory fish build up over the fish's entire lifetime, accumulating in the fish tissue as predatory fish consume other species in the food chain). Thus, fish and wildlife at the top of the food chain can have Hg concentrations that are higher than the lower species, and they can have concentrations of Hg that are higher than the concentration found in the water body itself. Therefore, the most common form of exposure to Hg for humans and wildlife is through the consumption of contaminated predatory fish, such as: Commercially consumed tuna, shark, or other saltwater fish species and recreationally caught bass, perch, walleye or other freshwater fish species. When humans consume fish contaminated with methylmercury, the ingested methylmercury is almost completely absorbed into the blood and distributed to all tissues (including the brain); it also readily passes through the placenta to the fetus and fetal brain.

Based on the findings of the National Research Council, EPA has concluded that benefits of Hg reductions would be most apparent at the human consumption stage, as consumption of fish is the major source of exposure to methylmercury. At lower levels, documented Hg exposure effects may include more subtle, yet potentially important, neurodevelopmental effects.

Some subpopulations in the U.S., such as: Native Americans, Southeast Asian Americans, and lower income subsistence fishers, may rely on fish as a primary source of nutrition and/or for cultural practices. Therefore, they consume larger amounts of fish than the general population and may be at a greater risk to the adverse health effects from Hg due to increased exposure. In pregnant women, methylmercury can be passed on to the developing fetus, and at sufficient exposure may lead to a number of neurological disorders in children. Thus, children who are exposed to low concentrations of methylmercury prenatally may be at increased risk of poor performance on neurobehavioral tests, such as those measuring attention, fine motor function, language skills, visual-spatial abilities (like drawing), and verbal memory. The effects from prenatal exposure can occur even at doses that do not result in effects in the mother. Mercury may also affect young children who consume fish contaminated with Hg. Consumption by children may lead to neurological disorders and developmental problems, which may lead to later economic consequences.

In response to potential risks of consuming fish containing elevated concentrations of Hg, EPA and FDA have issued fish consumption advisories which provide recommended limits on consumption of certain fish species for different populations. The EPA and FDA are currently developing a joint advisory that has been released in draft form. This newest draft FDA-EPA fish advisory recommends that women and young children reduce the risks of Hg consumption in their diet by moderating their fish consumption, diversifying the types of fish they consume, and by checking any local advisories that may exist for local rivers and streams. This collaborative FDA-EPA effort will greatly assist in educating the most susceptible populations. Additionally, the reductions of Hg from this regulation may potentially lead to fewer fish consumption advisories, which will benefit the fishing community.

Reducing emissions of Ni can also contribute to several benefits. We are concerned with the inhalation risks of Ni as the primary route of human exposure in this rulemaking. Nickel is found in ambient air at very low levels as a result of releases from oil combustion. The differing forms of Ni have varying levels of toxicity. There is great uncertainty about the type of Ni emitted. Respiratory effects have also been reported in humans who have been occupationally exposed to high levels of Ni. Human and animal studies have reported an increased risk of lung and nasal cancers from exposure to Ni refinery dusts and Ni subsulfide. Animal studies of soluble Ni compounds (*i.e.*, Ni carbonyl) have reported lung tumors. The EPA has classified Ni refinery subsulfide as a Group A carcinogen due to lung and nasal cancers in humans occupationally exposed to Ni refinery dust. Ni carbonyl is classified as a Group B2, probable human carcinogen based upon studies conducted in animals.

The proposed actions would also reduce NO_X and SO_2 emissions that contribute to the formation of fine particles ($PM_{2.5}$). In general, exposure to high concentrations of $PM_{2.5}$ may aggravate existing respiratory and cardiovascular disease including asthma, bronchitis and emphysema, especially in children and the elderly. Nitrogen oxides and SO_2 are also contributors to acid deposition, or acid rain, which causes acidification of lakes and streams and can damage trees, crops, historic buildings and statues. Exposure to $PM_{2.5}$ can lead to decreased lung function, and alterations in lung tissue and structure and in respiratory tract defense mechanisms which may then lead to, increased respiratory symptoms and disease, or in more severe cases, premature death or increased hospital admissions and emergency room visits. Children, the elderly, and people with cardiopulmonary disease, such as asthma, are most at risk from these health effects. Fine PM can also form a haze that reduces the visibility of scenic areas, can cause acidification of water bodies, and have other impacts on soil, plants, and materials.

As previously stated, the control technologies selected for analysis of the Hg portion of this action would also achieve reductions of NO_X and SO_2. Based on the scenario analyzed, the proposed section 112 MACT action would reduce approximately 902,000 tons of NO_X emissions, and 591,000 tons of SO_2 emissions. These projected reductions are due to the reliance on some SO_2 and NO_X controls and coal-switching to achieve Hg reductions. When compared to the base case, there is a projected shift towards lower sulfur bituminous coals (about 6 percent) that are also lower in Hg, which results in SO_2 emissions reductions. In addition, some units are projected to use SO_2 controls (scrubbers) to comply with the proposed section 112 MACT (about 1 GW), as well as generation shifts (about 1 percent) from uncontrolled units to units with scrubbers which would result in additional SO_2 reductions from the base case. Projected NO_X emissions reductions from the base case are a result of seasonal NO_X controls being operated annually in the MACT case to achieve additional Hg control (about 90 GW of SCR operate annually). Because NO_X and SO_2 contribute to the formation of $PM_{2.5}$, and because direct PM controls would be applied to meet the Ni requirements, these standards should lead to substantial benefits from reductions of ambient PM. Therefore, reduction of SO_2 and NO_X emissions from utilities will contribute to reduced human health and welfare impacts.

Due to both technical and resource limits in available modeling, we have only been able to quantify and monetize the benefits for a few of the endpoints associated with reducing Hg, Ni, directly emitted PM, and gaseous NO_X

and SO_2. However, based on relevant available modeling of several alternative control strategies to reduce Utility Unit SO_2 and NO_X emissions (including Clear Skies), we can approximate the benefits of reduced exposure to ambient PM resulting from reductions in precursor emissions of NO_X and SO_2. These benefit categories—including reductions in premature mortality—are believed to represent a dominant fraction of the total benefits associated with these proposed actions.

To quantify benefits, we evaluated PM-related health effects (including SO_2 and NO_X contributions to ambient concentrations of $PM_{2.5}$). Our approach requires the estimation of changes in air quality expected from the rule and the resulting effects on health. In order to characterize the benefits of today's proposed section 112 action, given the constraints on time and resources available for the analysis, we adopted a benefits transfer technique that relies on air quality and benefits modeling conducted for the recently proposed Clear Skies Act of 2003. Results from the Clear Skies analysis in 2010 are then scaled and transferred to the emission reductions expected from the proposed section 112 MACT rule.

This benefits assessment is conducted in two phases. First, using modeling runs developed in support of the Clear Skies legislation, we estimated the number of reduced incidences of illnesses, hospitalizations, and premature fatalities associated with a unit change in ambient concentrations of $PM_{2.5}$. The Clear Skies program covers a similar universe of affected sources and yields larger reductions in NO_X and SO_2 emissions. The distribution of emission reductions across states differs between the two analyses, especially in the Western U.S. Given the very small reductions in NO_X and SO_2 expected to occur in the Western U.S. as a result of the rule and the potential for errors in transferring benefits, we limit the benefits analysis to the Eastern U.S., and derive the benefits transfer factors from the Eastern U.S. Clear Skies benefits results only. Recognizing the differences in emission reduction patterns in the Eastern U.S. between the Clear Skies analysis and the current proposed MACT standards, we believe that the benefits per ton of SO_2 and NO_X estimated for the Clear Skies analysis represents a reasonable approximation of the benefits per ton that might be realized from the reductions in NO_X and SO_2 expected under the current proposed section 112 rule. The analysis of the proposed section 112 MACT includes only health benefits related to $PM_{2.5}$ reductions associated with the NO_X and SO_2 reductions, and does not include health benefits related to ozone reductions, visibility benefits, and other benefits including reduced nitrogen deposition and acidification. For the most part, quantifiable ozone benefits do not contribute significantly to the monetized benefits: thus, their omission does not materially affect the magnitude of estimated benefits. Visibility benefits may be more significant; although, visibility has generally contributed only a few percent of total monetized benefits.

Second, we used the Clear Skies analysis to develop a relationship between changes in ambient $PM_{2.5}$ concentrations and the underlying NO_X and SO_2 emission reductions to reflect differences in emissions reductions between the modeled Clear Skies scenario and the proposed standard. The sum of the scaled benefits for the SO_2 and NO_X emission reductions provide us with the total benefits of the rule.

The benefit estimates derived from the Clear Skies air quality modeling in the first phase of our analysis uses an analytical structure and sequence similar to that used in the benefits analyses for the proposed Nonroad Diesel rule and proposed IAQR and in the ''section 812 studies'' analysis of the total benefits and costs of the Clean Air Act. We used many of the same models and assumptions used in the Nonroad Diesel and IAQR analyses as well as other Regulatory Impact Analyses (RIAs) prepared by the Office of Air and Radiation. By adopting the major design elements, models, and assumptions developed for the section 812 studies and other RIAs, we have largely relied on methods which have already received extensive review by the independent Science Advisory Board (SAB), the National Academies of Sciences, by the public, and by other federal agencies. Interested parties will be able to obtain further information from the section 812 study on the kinds of methods we are likely to use for estimating benefits and costs in the final rule.

The benefits transfer method used in the second phase of the analysis is similar to that used to estimate benefits in the recent analysis of the proposed Nonroad Diesel rule and Nonroad Large Spark-Ignition Engines and Recreational Engines standards (67 FR 68241, November 8, 2002). A similar method has also been used in recent benefits analyses for the proposed Industrial Boilers and Process Heaters NESHAP and the Reciprocating Internal Combustion Engines NESHAP.

The economic and energy impact analysis memo (for the proposed section 112 MACT) details the control scenario as consisting of a combination of direct Hg controls and additional SO_2 and NO_X controls. Under this scenario, the extent of SO_2 and NO_X controls in Eastern U.S. would be limited to approximately 902,000 tons of NO_X and 591,000 tons of SO_2. As outlined above, these reductions drive the monetized benefits of the proposed rule, which would be approximately $15 billion (1999$). This economic benefit is associated with approximately 2,200 avoided premature mortalities, 1,200 avoided cases of chronic bronchitis, 2,900 avoided non-fatal heart attacks, thousands of avoided hospital and emergency room visits for respiratory and cardiovascular diseases, tens of thousands of avoided days with respiratory symptoms, and millions of avoided work loss and restricted activity days. The EPA recognizes that at the present time, these direct controls have not been adequately demonstrated, so this scenario reflects uncertain but possible advances in the availability of such controls. Under a more restrictive assumption about the availability of direct Hg controls (*e.g.*, ACI) than used in this analysis, Utility Unit control strategies may rely to an even greater extent on SO_2, NO_X, and direct PM control approaches to reduce Hg. In such an alternative MACT-only scenario, projected costs and benefits would be correspondingly much greater than those indicated in Table 8 of this preamble.

As noted above, however, consideration of the proposed section 112 MACT or proposed section 111 only scenarios does not capture the full dimension of the most likely air regulatory situation facing the power industry over the next decade. As noted above, EPA is also proposing significant additional SO_2 and NO_X reduction requirements to limit interstate transport of these pollutants. These requirements are likely to require Utility Units to install SO_2 and NO_X controls on significant fractions of their coal-fired capacity. For these reasons, there are strong public policy reasons to consider the combined influence of the Hg and IAQR requirements.

Table 8 of this preamble summarizes the results of the benefit-cost analysis of the proposed section 112 MACT scenario and compares them with estimates of the range of potential costs and benefits associated with an alternative scenario that addresses combined implementation of section 111 Hg requirements in coordination with proposed SO_2 and NO_X

requirements in the proposed IAQR. The potential influence of such a combined scenario is illustrated in the second column of Table 8 of this preamble, which assumes the proposed section 111 requirements are implemented in combination with the IAQR. The IAQR analysis projects that the Hg reductions associated with implementing the SO_2/NO_X requirements in the Eastern U.S. in 2010 would be approximately 10.6 tons per year, which is almost identical to those estimated from the proposed section 112 MACT-only scenario.

If the goal for the proposed section 111 program in 2010 is limited to these co-control reductions, there might be no additional costs or benefits to the program, over those achieved by the IAQR—this is indicated in the lower portion of the ranges in Table 8 of this preamble. By contrast, if the proposed section 111 regulation adopts a 2010 goal similar to the Phase I Clear Skies Hg cap, additional Hg reductions would be required over those forecast for the IAQR. Based on a multipollutant analyses conducted for Clear Skies (p D–9, Technical appendix D, at *http://www.epa.gov/airmarkets/epa-ipm*), power generators would likely opt for some additional SO_2 and NO_X controls beyond those needed for the IAQR, as well as considering additional direct Hg controls. Although the actual results are uncertain, the Clear Skies results suggest that the costs and benefits associated with a section 112 MACT-only approach may reflect a reasonable lower bound for the additional costs and benefits. These potential additional costs and benefits related to additional Hg controls are reflected in the upper end of the ranges in Table 8 of this preamble. In the decade beyond 2010, the proposed section 111 program would establish a 15 ton cap for Hg in 2018, similar to Clear Skies. Based on Clear Skies analyses, this would result in further Hg controls, which would likely include at least some additional SO_2/NO_X controls as well as direct Hg controls. The IAQR program alone produces only small additional reductions in Hg emissions in 2020. The Hg reductions estimated for the proposed section 112 MACT and the proposed section 111 and proposed IAQR programs are summarized in Table 9. These forecasts are based on IPM analyses of the proposed section 112 MACT scenario outlined above, the proposed IAQR analysis, and estimates derived from earlier analyses of the Clear Skies program.

Every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Deficiencies in the scientific literature often result in the inability to estimate changes in health and environmental effects. Deficiencies in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes that can be quantified. While these general uncertainties in the underlying scientific and economics literatures are discussed in detail in the RIA and its supporting documents and references, the key uncertainties which have a bearing on the results of the benefit-cost analysis of today's action are the following:

1. The exclusion of potentially significant benefit categories (*e.g.*, health and ecological benefits of reduction in hazardous air pollutants emissions);
2. Errors in measurement and projection for variables such as population growth;
3. Uncertainties in the estimation of future year emissions inventories and air quality;
4. Uncertainties associated with the extrapolation of air quality monitoring data to some unmonitored areas required to better capture the effects of the standards on the affected population;
5. Variability in the estimated relationships of health and welfare effects to changes in pollutant concentrations; and
6. Uncertainties associated with the benefit transfer approach.

Despite these uncertainties, we believe the benefit-cost analysis provides a reasonable indication of the expected economic benefits of the proposed actions under a given set of assumptions.

Based on estimated compliance costs (control + administrative costs associated with Paperwork Reduction Act requirements associated with the proposed rule and predicted changes in the price and output of electricity), the estimated social costs of the proposed section 112 MACT-only scenario are $1.6 billion (1999$). Social costs are different from compliance costs in that social costs take into account the interactions between affected producers and the consumers of affected products in response to the imposition of the compliance costs. In this action, coal-fired utilities are the affected producers and users of electricity are the consumers of the affected product.

As explained above, we estimate $15 billion in benefits from the proposed section 112 MACT, compared to less than $2 billion in costs. It is important to put the results of this analysis in the proper context. The large benefit estimate is not attributable to reducing human and environmental exposure to Hg. It arises from ancillary reductions in SO_2 and NO_X that result from controls aimed at complying with the proposed MACT. Although consideration of ancillary benefits is reasonable, we note that these benefits are not uniquely attributable to Hg regulation. Under the IAQR, coal-fired units would achieve much larger reductions in SO_2 and NO_X emissions than they would under the proposed section 112 MACT. In the years ahead, as the Agency and the States develop rules, guidance and policies to implement the new air quality standards for ozone and PM, coal-fired power plants will be required to implement additional controls to reduce SO_2 and NO_X (*e.g.*, scrubbers, SCR units, year-round NO_X controls in place of summertime only controls, conversion to low-sulfur coals, and so forth). Thus, most or all of the ancillary benefits of Hg control would be achieved anyway, regardless of whether a section 112 MACT is promulgated. Based on analysis of the Clear Skies legislation, EPA believes that the proposed 2018 Hg cap in the proposed section 111 rule would result in additional SO_2 and NO_X reductions beyond those that would be required under the proposed IAQR. Thus, the section 111 approach, unlike the section 112 approach, may achieve SO_2 and NO_X reduction benefits beyond those that would be achieved under the IAQR. We believe, however, that even if no Hg controls were imposed, most major coal-fired units would still have to reduce their SO_2 and NO_X emissions as part of the efforts to bring the nation into attainment with the new air quality standards. In light of these considerations, the Agency believes that the key rationale for controlling Hg is to reduce public and environmental exposure to Hg, thereby reducing risk to public health and wildlife. Although the available science does not support quantification of these benefits at this time, the Agency believes the qualitative benefits are large enough to justify substantial investment in Hg emission reductions.

It should be recognized, however, that this analysis does not account for many of the potential benefits that may result from these actions. The net benefits would be greater if all the benefits of the Hg, Ni, and other pollutant reductions

could be quantified. Notable omissions to the net benefits include all benefits of HAP reductions, including reduced cancer incidences, toxic morbidity effects, and cardiovascular and CNS effects, and all health and welfare effects from reduction of ambient NO_X and SO_2.

TABLE 8.—SUMMARY OF MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE PROPOSED SECTION 112 MACT STANDARD, [1] WITH A RANGE FOR POTENTIAL ALTERNATIVE SCENARIO ESTIMATES FOR MACT AND SECTION III PROPOSAL IN 2010 ($BILLIONS/YR)

	MACT-only Scenario	Sec. 111 plus IAQR Combined[4]
Social Costs[2]	$1.6	$2.9 to 4.5+
Social Benefits[3]:		
PM-related Health benefits	$15+B	$58 to 73+B
Net Benefits (Benefits – Costs)[3]	$13+B	$55 to $68+B

[1]All costs and benefits are rounded to two significant digits.
[2]Note that costs are the total costs of reducing all pollutants, including Hg and other metallic air toxics, as well as NO_X and SO_2 reductions. Benefits in this table are associated only with NO_X and SO_2.
[3]Not all possible benefits or disbenefits are quantified and monetized in this analysis. In particular, ozone health and welfare and PM welfare benefits are omitted. Other potential benefit categories that have not been quantified and monetized are listed in Table 5. B is the sum of all unquantified benefits and disbenefits.
[4]Estimated combined benefits of S. 111 plus IAQR costs and benefits in 2010. Ranges do not reflect actual analyses of combined programs. Rough estimates based on consideration of available IAQR, MACT, and Clear Skies analyses. See text.

TABLE 9.—FORECAST MERCURY EMISSIONS UNDER THE PROPOSED SECTION 112 MACT, AND THE PROPOSED SECTION 111 RULE AND THE PROPOSED IAQR[1]

Program/Year	2010	2020
MACT only	34	31
IAQR only	34	30
IAQR and section 111 caps	(2)	18–22

[1] Annual reductions from base case forecast under current programs to reduce Utility Unit emissions. MACT only value for 2015 based on interpolation of 2010 and 2015. Lower bound of IAQR and section 111 caps in 2010 assumes Hg cap is set at co-control level achieved by IAQR. Upper bound in 2010 and ranges thereafter estimates derived from Clear Skies analyses.
[2] Mercury emissions will reflect the level of emissions resulting from the co-benefits of controlling SO_2 and NO_X. See section IV.B.1 for a detailed discussion.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

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

Pursuant to the terms of Executive Order 12866, it has been determined that the proposed rule is an economically ''significant regulatory action'' because the annual cost may exceed $100 million dollars. As such, this action was submitted to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the public record.

B. Paperwork Reduction Act

The information collection requirements in the proposed NESHAP have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The ICR document prepared by EPA has been assigned EPA ICR No.____.

The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the Act (42 U.S.C. 7414). All information submitted to EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The proposed rule would require a monitoring plan submitted to the Administrator but would not require any reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance. The proposed rule would require notification in advance of complying with the rule by changing fuel.

The annual average monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years of this ICR) is estimated to total 243,000 labor hours per year. This includes 2 responses per year from 568 respondents for an average of 214 hours per response. The total annualized cost burden is estimated at $48.4 million, including labor, capital, and operation and maintenance. The capital costs of monitoring equipment are estimated at $66.8 million; the estimated annual cost for operation and maintenance of monitoring equipment is $15.4 million.

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

information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR part 63 are listed in 40 CFR part 9.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques, EPA has established a public docket for this proposed rule, which includes this ICR, under Docket ID number OAR–2003–0056. Submit any comments related to the ICR for this proposed rule to EPA and OMB. See the **ADDRESSES** section at the beginning of this notice for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503, Attention: Desk Office for EPA. Because OMB is required to make a decision concerning the ICR between 30 and 60 days after January 30, 2004, a comment to OMB is best assured of having its full effect if OMB receives it by March 1, 2004. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with the proposed rule. We have also determined that the proposed rule will not have a significant impact on a substantial number of small entities.

For purposes of assessing the impacts of the final rule on small entities, small entity is defined as:

(1) A small business according to Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity. For electric utilities, the size standard is 4 billion kilowatt-hours of production or less, respectively;

(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 impact of the proposed rule on small entities, we have determined that the proposed rule will not have a significant impact on a substantial number of small entities. Companies owning affected facilities as small businesses are projected to incur about 1.2 percent of the total compliance costs. Comparing these costs for small entities to their generation revenues, they represent about 1.3 percent of generation revenues.

An economic impact analysis was performed to estimate the changes in product price and production quantities for this action. As mentioned in the summary of economic impacts earlier in this preamble, the estimated changes in prices and output for affected firms is less than 1 percent.

This analysis, therefore, allows us to certify that there will not be a significant impact on a substantial number of small entities from the implementation of the proposed rule. For more information, consult the docket for the proposed rule.

We specifically solicit comment on the option to lower small entity costs through excluding units that release small amounts of Hg (*e.g.*, less than 25 pounds annually) from the phase II cap, while maintaining this cap for the largest sources of Hg.

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

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, we 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 a 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 objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows us 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 we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan under section 203 of the UMRA. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that the proposed rule contains a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Accordingly, we have prepared a written statement (titled ''Unfunded Mandates Reform Act Analysis for the Proposed Industrial Boilers and Process Heaters NESHAP)'' under section 202 of the UMRA which is summarized below.

1. Statutory Authority

As discussed in section I of this preamble, the statutory authority for the proposed rulemaking is sections 111 and 112 of the CAA. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. Section 112(b) of the CAA lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP.

Section 112(d) of the CAA directs us to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT based standards. This NESHAP applies to all fossil fuel-fired utility boilers located at major sources of HAP emissions as mentioned earlier in this preamble.

In compliance with section 205(a) of the UMRA, we identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives is presented in the docket.

The regulatory alternative upon which the proposed rule is based represents the MACT floor for fossil fuel-fired utility boilers and, as a result, it is the least costly and least burdensome alternative.

2. Social Costs and Benefits

The benefits and cost analyses prepared for the proposed rule are detailed in the ''Benefit Analysis of the CAA Section 111 Proposal To Reduce Mercury Emissions From Fossil-Fuel Fired Utilities'' and the ''Economic and Energy Impact Analysis of the Section 112 Utility MACT,'' respectively. Both of these reports are in the docket. Based on estimated compliance costs associated with the proposed rule and the predicted change in prices and production in the affected industry, the estimated social costs of the proposed rule are $1.6 billion (1999 dollars).

It is estimated that by 2010, Hg emissions will be reduced by the section 112 MACT rule to approximately 34 tons and Ni emissions reduced to approximately 103 tons. Studies have determined a relationship between exposure to these HAP and the onset of cancer and a number of other health effects. The Agency is unable to provide a monetized estimate of the benefits of the Hg and Ni emissions reduced by the proposed rule at this time. However, there are significant reductions in NO_X and SO_2 that occur. Reductions of NO_X amount to 902,000 tons and 591,000 tons of SO_2 are expected to occur. These reductions occur from existing sources in operation in 2010 and are expected to continue throughout the life of the affected sources. The major health effect that results from these NO_X and SO_2 emissions reductions is a reduction in premature mortality. Other health effects that occur are reductions in chronic bronchitis, asthma attacks, and work-lost days (*i.e.*, days when employees are unable to work).

While we are unable to monetize the benefits associated with the Hg and Ni HAP emissions reductions, we are able to monetize the benefits associated with the PM and SO_2 emissions reductions. For NO_X and SO_2, we estimated the benefits associated with reductions of health effects but were unable to quantify all categories of benefits (particularly those associated with ecosystem and environmental effects). Estimates of the benefits and costs of the SO_2 and NO_X emission reductions associated with the proposed actions are presented in Table 8 above. Unquantified benefits are noted with ''B'' in the estimates presented below.

3. Future and Disproportionate Costs

The Unfunded Mandates Act requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by the proposed rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of the proposed rule are discussed in section_of this preamble.

We do not believe that there will be any disproportionate budgetary effects of the proposed rule on any particular areas of the country, State or local governments, types of communities (*e.g.*, urban, rural), or particular industry segments. This is true for the 28 facilities owned by about 80 different government bodies, and this is borne out by the results of the ''Economic and Energy Impact Analysis of the Utility MACT,'' the results of which are discussed in a previous section of this preamble.

4. Effects on the National Economy

The Unfunded Mandates Act requires that we estimate the effect of the proposed rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of the proposed rule is presented in the ''Economic and Energy Impact Analysis for the Utility MACT'' in the docket. This analysis provides estimates of the effect of the proposed rule on some of the categories mentioned above. The results of the economic impact analysis are summarized in a previous section of this preamble.

5. Consultation With Government Officials

The Unfunded Mandates Act requires that we describe the extent of the Agency's prior consultation with affected State, local, and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, section 203 of the UMRA requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a proposal. Although the proposed rule does not affect any State, local, or tribal governments, we have consulted with State and local air pollution control officials. We also have held meetings on the proposed rule with many of the stakeholders from numerous individual companies, environmental groups, consultants and vendors, labor unions, and other interested parties. We have added materials to the Air docket to document these meetings.

In addition, we have determined that the proposed rule contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have some sources affected by the proposed rule, the impacts are not expected to be significant. Therefore, today's proposed rule is 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 proposed 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.

Although section 6 of Executive Order 13132 does not apply to the proposed rule, we consulted with representatives of State and local governments to enable them to provide meaningful and timely input into the development of the proposed rule. This consultation took place during the FACA committee meetings where members representing State and local governments participated in developing recommendations for this rulemaking. The concerns raised by representatives of State and local governments were considered during the development of the proposed rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on the proposed rule from State and local officials.

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

Executive Order 13175 (65 FR 67249, November 6, 2000) requires the 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.''

Under section 5(b) of Executive Order 13175, EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by Tribal governments, or EPA consults with Tribal officials early in the process of developing the proposed regulation. Under section 5(c) of Executive Order 13175, EPA may not issue a regulation that has Tribal implications and that preempts tribal law, unless the Agency consults with Tribal officials early in the process of developing the proposed regulation.

The EPA has concluded that the proposed rule may have Tribal implications because two coal-fired Utility Units are located in Indian Country. Based on a review of information available to EPA at this time about the operations at these two plants, the Agency concluded that compliance of the plants with the requirements of the proposed rule would not impose substantial direct compliance costs on the affected Tribal governments. The EPA specifically solicits additional comment from Tribal officials on the proposed rule's potential impacts on Utility Units located in Indian Country.

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

Executive Order 13045, ''Protection of Children From Environmental Health Risks and Safety Risks'' (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, Section 5–501 of the Order directs the Agency to evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives.

In accordance with the Order, the Agency evaluated the environmental and health and safety effects of the proposed rule, and for the reasons explained above, the Agency believes that the proposed strategies are preferable to other potentially effective and reasonably feasible alternatives. The strategies proposed in this rulemaking will further improve air quality and will further improve children's health.

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

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of final rulemaking, and notices of final rulemaking: (1) (i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a ''significant energy action.'' The proposed rule is a ''significant energy action'' because it is likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for the determination is as follows.

Compared to 2010 projections of existing statutory and regulatory requirements, coal-fired and gas-fired electricity generation are projected to remain relatively unchanged by this action. When compared to 2010 projections of existing statutory and regulatory requirements, about 900 MW of coal-fired capacity is projected to be uneconomic to maintain. Coal production for the electric power sector is expected to increase from 2000 levels, about 147 million tons or 16 percent. When compared to 2010 projections of existing statutory and regulatory requirements, the nationwide price of fuel for the electric power sector, both coal and natural gas remain relatively unchanged by this action, with coal prices projected to remain unchanged and gas prices projected to increase less than 1 percent. Nationwide retail electricity prices are projected to gradually decline from 2000 levels but then rise over time. Prices are projected to drop initially due to excess generation capacity; in 2010 prices are projected to increase due to new capacity requirements, which lead to higher capital costs and greater natural gas use, and higher retail prices passed on to consumers. In 2020, retail electricity prices are projected to still be below 2000 prices. When compared to 2010 projections of existing statutory and regulatory requirements, electricity prices are projected to increase less than 1 percent. We also expect that there will be no discernible impact on the import of foreign energy supplies, and no other adverse outcomes are expected to occur with regards to energy supplies. For more information on the estimated energy effects, please refer to the economic and energy impact analysis memo for the proposed rule. The analysis is available in the public docket. Total annual costs of this action are projected to be up to $1.6 billion in 2010, depending on other actions that EPA or States might take to control SO_2 and NO_X emissions. These costs represent about a 1.9 percent increase in annual electricity production costs.

Because this proposed regulation has greater than a 1 percent impact on the cost of electricity production and because it results in the retirement of greater than 500 MW of coal-fired generation (the retirement estimate is 900 MW), this regulation is significant. It should be noted that EPA has proposed a trading program to achieve Hg reduction as an alternative to the MACT standard, which is a command and control regulation. The relative flexibility offered by a trading program may ease the impact on energy production.

I. National Technology Transfer and 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 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 the OMB, with explanations when EPA does not use available and applicable voluntary consensus standards.

This rulemaking involves technical standards.

List of Subjects

40 CFR Part 60

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

40 CFR Part 63

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

Dated: December 15, 2003.

Michael O. Leavitt,

Administrator.

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

Note: There are two options proposed for comment. Based on the comments we receive on this proposal, we will promulgate either Option 1 or Option 2.

Option 1—Proposed Amendments to Parts 60 and 63

PART 60—[AMENDED]

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

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

2. Section 60.17 is amended by adding paragraph (a)(65) to read as follows:

§ 60.17 Incorporations by Reference.

* * * * *

(a) * * *

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

* * * * *

APPENDIX B PART 60

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

Performance Specification 12a—Specifications and Test Procedures for Total Vapor Phase Mercury Continuous Emission Monitoring Systems in Stationary Sources

1.0 Scope and Application.

1.1 Analyte.

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

1.2 Applicability.

1.2.1 This specification is for evaluating the acceptability of total vapor phase Hg continuous emission monitoring systems (CEMS) installed on the exit gases from fossil fuel fired boilers at the time of or soon after installation and whenever specified in the regulations. The Hg CEMS must be capable of measuring the total concentration in $\mu g/m^3$ (regardless of speciation) of vapor phase Hg, and recording that concentration on a dry basis, corrected to 20 degrees C and 7 percent CO_2. Particle bound Hg is not included. The CEMS must include (a) a diluent (CO_2) monitor, which must meet Performance Specification 3 in 40 CFR part 60, appendix B, and (b) an automatic sampling system. Existing diluent and flow monitoring equipment can be used.

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 CAA section 114, the operator to conduct CEMS performance evaluations at other times besides the initial test to evaluate the CEMS performance. See 40 CFR 60.13(c).

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 CEMS that measures the total vapor phase Hg mass concentration and generates a proportional output.

3.4 *Diluent Analyzer* (if applicable) means that portion of the CEMS that senses the diluent gas (CO_2) and generates an output proportional to the gas concentration.

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

3.6 *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.

3.7 *Measurement Error (ME)* means the difference between the concentration indicated by the CEMS and the known concentration generated by a reference gas when the entire CEMS, including the sampling interface, is challenged. An ME test procedure is performed to document the accuracy and linearity of the CEMS at several points over the measurement range.

3.8 *Upscale Drift (UD)* means the difference in the CEMS output responses to a Hg reference gas 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 *Zero Drift (ZD)* means the difference in the CEMS output responses to a zero gas 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.

3.10 *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 or the applicable emission limit.

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 reference method 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 CEMS data recorder output range must include zero and a high level value. The high level value must be approximately 2 times the Hg concentration corresponding to the emission standard level for the stack gas under the circumstances existing as the stack gas is sampled. If a lower high level value is used, the CEMS must have the capability of providing multiple high level values (one of which is equal to the span value) or be capable of automatically changing the high level value as required (up to specified high level value) such that the measured value does not exceed 95 percent of the high level value.

6.1.2 The CEMS design should also provide for the determination of response drift at both the zero and mid-level value. If this is not possible or practical, the design must allow these determinations to be conducted at a low-level value (zero to 20 percent of the high-level value) and at a 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.

7.1.1 Zero—N_2 or Air. Less than 0.1 µg Hg/m^3.

7.1.2 Mid-level Hg^0 and $HgCl_2$. 40 to 60 percent of span.

7.1.3 High-level Hg^0 and $HgCl_2$. 80 to 100 percent of span.

7.2 Reagents and Standards. May be required for the reference methods. See Section 8.6.2.

8.0 Performance Specification 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 eight equivalent diameters downstream of the nearest control device, point of pollutant generation, bend, or other point at which a change of pollutant concentration or flow disturbance may occur, and (2) at least two equivalent diameters 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 Reference Method (RM) Measurement Location and Traverse Points. The RM measurement location should be at a point or points in the same stack cross sectional area as the CEMS is located, according to the criteria above. The RM and CEMS locations need not be immediately adjacent. They should be as close as possible without causing interference with one another.

8.3 Measurement Error (ME) Test Procedure. The Hg CEMS must be constructed to permit the introduction of known (NIST traceable) concentrations of elemental mercury (Hg^0) and mercuric chloride ($HgCl_2$) separately into the sampling system of the CEMS immediately preceding the sample extraction filtration system such that the entire CEMS can be challenged. Inject sequentially each of the three reference gases (zero, mid-level, and high level) for each Hg species. CEMS measurements of each reference gas shall not differ from their respective reference values by more than 5 percent of the span value. If this specification is not met, identify and correct the problem before proceeding.

8.4 Upscale Drift (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) for 7 consecutive days according to the procedure given in Sections 8.4.2 through 8.4.3.

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 the mid-level point specified in Section 7.1. Evaluate upscale drift for elemental Hg (Hg^0) only. Introduce the reference gas to the CEMS. Record the CEMS response and subtract the reference value from the CEM value (see example data sheet in Figure 12A–1).

8.5 Zero Drift (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) for 7 consecutive days according to the procedure given in Sections 8.5.2 through 8.5.3.

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 CEM value (see example data sheet in Figure 12A–1).

8.6 Relative Accuracy (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 can be conducted during the UD test period.

8.6.2 Reference Method (RM). Unless otherwise specified in an applicable subpart of the regulations, use either Method 29 in appendix A to 40 CFR part 60, or ASTM Method D 6784–02 (incorporated by reference in § 60.17) as the RM for Hg. Do not include the filterable portion of the sample when making comparisons to the CEMS results. Conduct all RM tests with paired or duplicate sampling systems.

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 the diluent (if applicable), moisture (if needed), and Hg measurements simultaneously. However, diluent and moisture measurements that are taken within an hour of the Hg measurements can be used to adjust the results to a consistent 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 paired sets of all necessary RM test runs that meet the relative standard deviation criteria of this PS. Use a minimum sample run time of 2 hours for each pair.

Note: More than nine paired sets of RM tests can be performed. If this option is chosen, test results can be rejected 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 rejected 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 or emission rate for each pollutant RM test period. Consider system response time, if important, and confirm that the results are on a consistent moisture, temperature, and diluent concentration basis with the paired RM test. Then, compare each integrated CEMS value against the corresponding average of the paired RM values.

8.6.6 Paired RM Outliers.

8.6.6.1 Outliers are identified through the determination of precision and any systematic bias 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 dual RM sampling is to generate information to quantify the precision of the RM data. The relative standard deviation (RSD) of paired data is the parameter used to quantify data precision. Determine RSD for two simultaneously gathered data points as follows:

$$RSD = 100\% * |(Ca - Cb)| / (Ca + Cb) \qquad \text{Eq. 12A-1}$$

where:
Ca and Cb are concentration values determined from trains A and B respectively. For RSD calculation, the concentration units are unimportant so long as they are consistent.

8.6.6.2 A minimum precision criteria for RM Hg data is that RSD for any data pair must be ≤10 percent as long as the mean Hg concentration is greater than 1.0 μg/m³. If the mean Hg concentration is less than or equal to 1.0 μg/m³, the RSD must be ≤20 percent. Pairs of RM data exceeding these RSD 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 the emission standard, 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 Performance Specification (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 Performance Specification 2.

12.1 Consistent Basis. All data from the RM and CEMS must be on a consistent dry basis and, as applicable, on a consistent diluent basis. Correct the RM and CEMS data for moisture and diluent as follows:

12.1.1 Moisture Correction (as applicable). Correct each wet RM run for moisture with the corresponding Method 4 data; correct each wet CEMS run using the corresponding CEMS moisture monitor date using Equation 12A–2.

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

12.1.2 Correction to Units of Standard (as applicable). Correct each dry RM run to the units of the emission standard with the corresponding Method 3B data; correct each dry CEMS run using the corresponding CEMS diluent monitor data as follows:

12.1.3 Correct to Diluent Basis. The following is an example of concentration (ppm) correction to 7 percent oxygen.

$$\text{ppm}_{(corr)} = \text{ppm}_{(uncorr)}\left[\frac{20.9 - 7.0}{20.9 - \%O_{2\,(dry)}}\right] \qquad \text{Eq. 12A-3}$$

The following is an example of mass/gross calorific value (lbs/million Btu) correction.

lbs/MMBtu = Conc($_{dry}$) (F-factor) ((20.9/(20.9 − percent O_2))

12.2 Arithmetic Mean. Calculate the arithmetic mean of the difference, d, of a data set as follows:

$$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i \qquad \text{Eq. 12A-4}$$

Where:
n = Number of data points.

12.3 *Standard Deviation. Calculate the standard deviation,* S_d, as follows:

$$S_d = \left[\frac{\sum_{i=1}^{n} d_i^2 - \frac{\left[\sum_{i=1}^{n} d_i\right]^2}{n}}{n-1}\right]^{\frac{1}{2}} \qquad \text{Eq. 12A-5}$$

Where:

$$\sum_{i=1}^{n} d_i = \text{Algebraic summation of the individual differences } d_i.$$

12.4 Confidence Coefficient. Calculate the 2.5 percent error confidence coefficient (one-tailed), CC, as follows:

$$CC = t_{0.975}\frac{S_d}{\sqrt{n}} \qquad \text{Eq. 12A-6}$$

12.5 Relative Accuracy. Calculate the RA of a set of data as follows:

$$RA = \frac{\left[\left|\bar{d}\right| + \left|CC\right|\right]}{\overline{RM}} \times 100 \qquad \text{Eq. 12A-7}$$

Where:
$|\bar{d}|$ = Absolute value of the mean differences (from Equation 12A–4).
|CC| = Absolute value of the confidence coefficient (from Equation 12A–6).
RM = Average RM value. In cases where the average emissions for the test are less than 50 percent of the applicable standard, substitute the emission standard value in the denominator of Eq. 12A–7 in place of RM. In all other cases, use RM.

13.0 Method Performance.

13.1 Measurement Error (ME). ME is assessed at 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 span. The same difference for the zero reference gas shall be no greater than 5 percent of span.

13.2 Upscale Drift (UD). The CEMS design must allow the determination of UD of the analyzer. The CEMS response can not drift or deviate from the benchmark value of the reference standard by more than 5 percent of span for the mid level value. Evaluate upscale drift for Hg^0 only.

13.3 Zero Drift (ZD). The CEMS design must allow the determination of drift at the

zero level. This drift shall not exceed 5 percent of span.

13.4 Relative Accuracy (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 the emission standard, or 10 percent of the applicable standard, whichever is greater.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 Alternative Procedures. [Reserved]

17.0 Bibliography.

17.1 40 CFR part 60, appendix B, ''Performance Specification 2—Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources.''

17.2 40 CFR part 60, appendix A, ''Method 29—Determination of Metals Emissions from Stationary Sources.''

17.3 ASTM Method D6784–02, ''Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method).''

18.0 Tables and Figures

TABLE 12A–1.—t-VALUES

n [a]	$t_{0.975}$	n_a	$t_{0.975}$	n_a	$t_{0.975}$
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	15	2.145
6	2.571	11	2.228	16	2.131

[a] The values in this table are already corrected for n–1 degrees of freedom. Use n equal to the number of individual values.

	Day	Date and time	Reference value (C)	CEMS value (M)	Measurement error	Drift
Zero Level						
Mid-level						
High-level						

Figure 12A–1. Zero and Upscale Drift Determination.

PART 63—[AMENDED]

4. The authority citation for part 63 continues to read as follows:

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

5. Section 63.14 is amended by adding paragraph (b)(35) to read as follows:

§ 63.14 Incorporations by Reference.

* * * * *

(b) * * *

(35) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), for appendix B to part 63, Method 324.

* * * * *

6. Part 63 is amended by adding subpart UUUUU to read as follows:

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants for Coal-or Oil-Fired Electric Utility Steam Generating Units

Sec.

What This Subpart Covers

63.9980 What is the purpose of this subpart?

63.9981 Am I subject to this subpart?

63.9982 What parts of my facility does this subpart cover?

63.9983 When do I have to comply with this subpart?

Emissions Limitations

63.9990 What emissions limitations must I meet for coal-fired electric utility steam generating units?

63.9991 What emissions limitations must I meet for oil-fired electric utility steam generating units?

63.9992 What are my compliance options for multiple affected sources?

General Compliance Requirements

63.10000 What are my general requirements for complying with this subpart?

Initial Compliance Requirements

63.10005 By what date must I conduct performance tests or other initial compliance demonstrations?

63.10006 When must I conduct subsequent performance tests?

63.10007 What performance test procedures must I use?

63.10008 What are my monitoring, installation, operation, and maintenance requirements?

63.10009 How do I demonstrate initial compliance with the emissions limitations?

Continuous Compliance Requirements

63.10020 How do I monitor and collect data to demonstrate continuous compliance?

63.10021 How do I demonstrate continuous compliance with the emissions limitations?

Notifications, Reports, and Records

63.10030 What notifications must I submit and when?
63.10031 What reports must I submit and when?
63.10032 What records must I keep?
63.10033 In what form and how long must I keep my records?

Other Requirements and Information

63.10040 What parts of the General Provisions apply to me?
63.10041 Who implements and enforces this subpart?
63.10042 What definitions apply to this subpart?

Tables to Subpart UUUUU of Part 63

Table 1 to Subpart UUUUU of Part 63—Performance Test Requirements for Ni and Hg
Table 2 to Subpart UUUUU of Part 63—Initial Compliance With Emissions Limitations for Ni and Hg
Table 3 to Subpart UUUUU of Part 63—Continuous Compliance with Emissions Limitations for Hg and Ni
Table 4 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU

What This Subpart Covers

§ 63.9980 What is the purpose of this subpart?

This subpart establishes national emissions limitations for hazardous air pollutants (HAP) emitted from coal-fired electric utility steam generating units and oil-fired electric utility steam generating units. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emissions limitations.

§ 63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired electric utility steam generating unit or an oil-fired electric utility steam generating unit.

§ 63.9982 What parts of my facility does this subpart cover?

(a) The affected source is each group of one or more coal- or oil-fired electric utility steam generating units located at a facility. An electric utility steam generating unit that combusts natural gas at greater than or equal to 98 percent of the unit's annual fuel consumption is not an affected source under this subpart.

(b) A coal or oil-fired electric utility steam generating unit is a new affected source if you commenced construction of the unit after January 30, 2004.

(c) An affected source is reconstructed if you meet the criteria as defined in § 63.2. An existing electric utility steam generating unit that is switched completely to burning a different coal rank or fuel type is considered to be an existing affected source under this subpart.

(d) An affected source is existing if it is not new or reconstructed.

§ 63.9983 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to paragraph (a)(1) or (2) of this section.

(1) If you start up your affected source before [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**], then you must comply with the emissions limitations and work practice standards for new and reconstructed sources in this subpart no later than [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**].

(2) If you startup your affected source on or after [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**], then you must comply with the emissions limitations and work practice standards for new and reconstructed sources in this subpart upon startup of your affected source.

(b) If you have an existing affected source, you must comply with the emissions limitations for existing sources no later than 3 years after [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**].

(c) You must meet the notification requirements according to the schedule applicable to your facility as specified in § 63.10300 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emissions limitations in this subpart.

Emissions Limitations

§ 63.9990 What emissions limitations must I meet for coal-fired electric utility steam generating units?

(a) For each coal-fired electric utility steam generating unit other than an integrated gasification combined-cycle (IGCC) electric utility steam generating unit, you must meet the mercury (Hg) emissions limit in paragraphs (a)(1) through (5) of this section that applies to your unit. 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 § 63.10009.

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must meet the Hg emissions limit in either paragraph (a)(1)(i) or (ii) of this section that applies to you.

(i) You must not discharge into the atmosphere from an existing affected source any gases which contain Hg in excess of 2.0 pound per trillion British thermal unit (lb/TBtu) on an input basis or 21×10^{-6} pound per Megawatt hour (lb/MWh) on an output basis.

(ii) You must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 6.0×10^{-6} lb/MWh on an output basis.

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal, you must meet the Hg emissions limit in either paragraph (a)(2)(i) or (ii) of this section that applies to you.

(i) You must not discharge into the atmosphere any gases from an existing affected source which contain Hg in excess of 5.8 lb/TBtu on an input basis or 61×10^{-6} lb/MWh on an output basis.

(ii) You must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 20×10^{-6} lb/MWh on an output basis.

(3) For each coal-fired electric utility steam generating unit that burns only lignite coal, you must meet the Hg emissions limit in either paragraph (a)(3)(i) or (ii) of this section that applies to you.

(i) You must not discharge into the atmosphere any gases from an existing affected source which contain Hg in excess of 9.2 lb/TBtu on an input basis or 98×10^{-6} lb/MWh on an output basis.

(ii) You must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 62×10^{-6} lb/MWh on an output basis.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must meet the Hg emissions limit in either paragraph (a)(4)(i) or (ii) of this section that applies to you.

(i) You must not discharge into the atmosphere any gases from an existing affected source which contain Hg in excess of 0.38 lb/TBtu on an input basis or 4.1×10^{-6} lb/MWh on an output basis.

(ii) You must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 1.1×10^{-6} lb/MWh on an output basis.

(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 or existing 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 your 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 or existing affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the proportion of energy output (in Btu) contributed by each coal type 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.

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

Where:

EL_b = Total allowable Hg in lb/MWh (or lb/TBtu) 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 that applies to affected source i, lb/MWh (or lb/TBtu).

HH_i = Heat input to, or electricity output from, affected source i during the production period related to the corresponding H_i that falls within the compliance period, gross MWh generated or MMBtu heat input to the electric utility steam generating unit.

n = Number of 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 energy output (in Btu) contributed by each coal type 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 both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, you must meet the Hg emissions limit in either paragraph (b)(1) or (2) of this section that applies to you. The Hg emissions limits in this paragraph are based on a 12-month rolling average using the procedures in § 63.10009.

(1) You must not discharge into the atmosphere any gases from an existing affected source which contain Hg in excess of 19 lb/TBtu on an input basis or 200 x 10^{-6} lb/MWh on an output basis.

(2) You must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 20×10^{-6} lb/MWh on an output basis.

§ 63.9991 What emissions limitations must I meet for oil-fired electric utility steam generating units?

(a) For each oil-fired electric utility steam generating unit, you must meet the nickel (Ni) emissions limit in paragraphs (a)(1) and (2) of this section that applies to you, except as provided in paragraph (b) of this section.

(1) You must not discharge into the atmosphere any gases from an existing affected source which contain Ni in excess of 210 lb/TBtu on an input basis or 0.002 lb/MWh on an output basis.

(2) You must not discharge into the atmosphere any gases from a new affected source which contain Ni in excess of 0.0008 lb/MWh on an output basis.

(b) The emissions limit in paragraph (a) of this section does not apply to a new or existing oil-fired electric utility steam generating unit if during the reporting period, to burn 98 percent or more distillate oil exclusively as the fuel for the unit. The emissions limit in paragraph (a) of this section will apply immediately if you subsequently burn a fuel other than distillate oil in the unit.

(c) If you use an electrostatic precipitator (ESP) to meet the applicable Ni emissions limit, you must operate the ESP such that the hourly average voltage and secondary current (or total power input) do not fall below the limit established in the initial or subsequent performance test.

(d) If you use a control device or combination of control devices other than an ESP to meet the applicable Ni emissions limit, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters for an ESP, you must apply to the Administrator for approval of alternative monitoring under § 63.8(f).

§ 63.9992 What are my compliance options for multiple affected sources?

(a) If you have two or more coal-fired electric utility steam generating units at your facility that are subject to Hg emission limits in § 63.9990, you may choose to use the emissions averaging compliance approach specified in paragraph (b) of this section as an alternative to complying with the applicable Hg emission limits for each individual unit. You may use emissions averaging only under the conditions specified in paragraphs (a)(1) and (2) of this section.

(1) The emissions averaging compliance approach is applicable to coal-fired electric utility steam generating units subject to the Hg emission limits for existing affected sources under this subpart that are located at a common contiguous facility. The emissions averaging compliance approach is also applicable to coal-fired electric utility stream generating units subject to the Hg emission limits for new affected sources under this subpart as long as they meet the new source limits specified under this subpart.

(2) All of the Hg emission limits used for the emissions averaging compliance approach must meet the applicable limits expressed in the same format (*i.e.*, all of the Hg emission limits must be either the applicable lb/TBtu limit values or the applicable lb/MWh limit values).

(b) If you choose to use the emissions averaging compliance approach, you must meet the requirements specified in paragraphs (b)(1) through (5) of this section.

(1) You must designate your emissions averaging source group by identifying each of the existing coal-fired electric utility stream generating units at your facility site to be included in your emissions averaging source group.

(2) You must designate a common Hg emissions limit format to be used for all of the coal-fired electric utility stream generating units in your designated emissions averaging source group (either the lb/TBtu limit format or the lb/MWh limit format).

(3) You must determine the Hg emissions limit value in § 63.9990 for your selected format that is applicable to each of the individual coal-fired electric utility stream generating units in your designated emissions averaging source group.

(4) You must calculate the unit-specific Hg emissions limit for your

designated emissions averaging source group using Equation 1 of this section.

$$AvEL = \frac{\sum_{i=1}^{n} L_i(V_i)}{\sum_{i=1}^{n} V_i} \qquad \text{(Eq. 1)}$$

Where:

AvEL = Total allowable Hg that can be emitted to the atmosphere from all emission sources in the emissions averaging group, lb/MWh or lb/TBtu;

L_i = Hg emissions limit for the subcategory that applies to emission source i or the calculated emissions limit derived for an emissions averaging group using Equation 1 of this section, lb/MWh or lb/MMBtu;

V_i = Volume of production for emissions source i during the production period related to the corresponding L_i that falls within the 12-month compliance period, gross MWh generated or MMBtu heat input to the electric utility steam generating unit; and

n = Number of emissions sources being averaged. This number may apply to individual emissions sources or emissions averaging groups.

(5) You must not discharge into the atmosphere any gases from your designated emissions averaging group that contain Hg in excess of the unit-specific Hg emissions limit established according to paragraph (b)(4) of this section as determined based on a 12-month rolling average using the procedures in § 63.10009.

(c) You may use the emissions averaging compliance approach or revise an existing emissions averaging group at any time after the compliance date by submitting an emissions averaging plan or revision, respectively, using the title V operating permit amendment process specified by the regulating authority. The emissions averaging plan must contain the information specified in paragraphs (c)(1) and (2) of this section.

(1) Identification of each coal-fired electric utility steam generating unit in your designated emissions averaging group and the applicable Hg emissions limit for each unit as determined in paragraph (b) of this section.

(2) The Hg emissions limit for your designated emissions averaging group as determined in paragraph (b) of this section, including all calculations and supporting information.

General Compliance Requirements

§ 63.10000 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emissions limitations (including operating limits) in this subpart at all times, except during periods of startup, shutdown, and malfunction.

(b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in § 63.6(e)(1)(i).

(c) For each monitoring system required by this subpart, you must develop and submit to the Administrator for approval a unit-specific monitoring plan according to the requirements in § 63.10008(f).

(d) You must conduct a performance evaluation of each continuous monitoring system (CMS) in accordance with your unit-specific monitoring plan.

(e) You must operate and maintain the CMS in continuous operation according to the unit-specific monitoring plan.

(f) You must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in § 63.6(e)(3).

Initial Compliance Requirements

§ 63.10005 By what date must I conduct performance tests or other initial compliance demonstrations?

(a) For each existing affected source, you must conduct performance tests, set operating limits, and conduct monitoring equipment performance evaluations, as applicable to your source, by the compliance date that is specified for your source in § 63.9983 and according to the applicable provisions in § 63.7(a)(2).

(b) For each new affected source, you must conduct performance tests, set operating limits, and conduct monitoring equipment performance evaluations, as applicable to your source, within 180 days after the compliance date that is specified for your source in § 63.9983 and according to the provisions in § 63.7(a)(2).

§ 63.10006 When must I conduct subsequent performance tests?

For each affected oil-fired electric utility steam generating units subject to a Ni emissions limit in this subpart, you must conduct a subsequent performance test at least once each year to demonstrate compliance and include the results in the next semiannual compliance report.

§ 63.10007 What performance test procedures must I use?

(a) For each affected oil-fired electric utility steam generating unit subject to a Ni emissions limit under this subpart, you must conduct each performance test to demonstrate compliance with the applicable emissions limit according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) You must conduct each performance test according to § 63.7(c), (d), (f), and (h) and the procedures in Table 1 to this subpart. You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(2) You must conduct each performance test at the representative process operating conditions that are expected to result in the highest emissions of Ni, and you must demonstrate initial compliance and establish your operating limits based on this test.

(3) You may not conduct performance tests during periods of startup, shutdown, or malfunction.

(4) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour.

(b) You must submit a Notification of Compliance Status report containing the results of the initial or annual compliance demonstration according to the requirements in § 63.10031(b).

§ 63.10008 What are my monitoring, installation, operation, and maintenance requirements?

(a) If you use an ESP to meet a Ni limit in this subpart, you must install and operate a continuous parameter monitoring system (CPMS) to measure and record the voltage and secondary current (or total power input) to the control device.

(b) You must install, operate, and maintain each CPMS by the compliance date specified in § 63.9983 according to the requirements in paragraphs (b)(1) through (3) of this section.

(1) Each CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Each CPMS must determine the 1-hour block average of all recorded readings.

(3) You must record the results of each inspection, calibration, and validation check for a CPMS.

(c) You must install and operate a continuous emissions monitoring system (CEMS) to measure and record

the concentration of Hg in the exhaust gases from each stack.

(d) You must install, operate, and maintain each CEMS by the compliance date specified in § 63.9983 according to the requirements in paragraphs (d)(1) through (4) of this section.

(1) You must install, operate, and maintain each CEMS according to Performance Specification 12A in 40 CFR part 60, appendix B.

(2) You must conduct a performance evaluation of each CEMS according to the requirements of § 63.8 and Performance Specification 12A in 40 CFR part 60, appendix B. id.

(3) You must operate each CEMS according to the requirements in paragraphs (d)(3)(i) through (iv) of this section.

(i) As specified in 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) You must reduce CEMS data as specified in § 63.8(g)(2).

(iii) Each CEMS must determine and record the 1 hour average emissions using all the hourly averages collected for periods during which the CEMS is not out of control.

(iv) You must record the results of each inspection, calibration, and validation check.

(4) The provisions in paragraphs (d)(4)(i) through (iv) of this section apply to data collection periods for your Hg CEMS.

(i) A complete day of data for continuous monitoring is 18 hours or more in a 24-hour period.

(ii) A complete month of data for continuous monitoring is 21 days or more in a calendar month.

(iii) If you collect less than 21 days of continuous emissions data, you must discard the data collected that month and replace that data with the mean of the individual monthly emission rate values determined in the last 12 months.

(iv) If you collect less than 21 days per monthly period of continuous data again in that same 12-month rolling average cycle, you must discard the data collected that month and replace that data with the highest individual monthly emission rate determined in the last 12 months.

(e) As an alternative to the CEMS required in paragraph (c) of this section, the owner or operator must monitor Hg emissions using Method 324 in 40 CFR part 63, appendix A.

(f) You must prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system. You must comply with the requirements in your plan. The plan must address the requirements in paragraphs (f)(1) through (6) of this section.

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

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1), (3), and (4)(ii);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(6) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1) and (e)(2)(i).

(g) Quarterly accuracy determinations and daily calibration drift tests for gaseous Hg CEMS shall be performed in accordance with Procedure 1 (appendix F of 40 CFR part 60). Annual relative accuracy test audits (RATAs) for Hg sorbent trap monitoring systems shall also be performed in accordance with Procedure 1.

§ 63.10009 How do I demonstrate initial compliance with the emissions limitations?

(a) You must demonstrate initial compliance with each emission limitation in § 63.9990 that applies to you according to Table 2 to this subpart.

(b) If you elect to comply with an emissions limit using emissions averaging according to the requirements in § 63.9992, you must demonstrate compliance with the emissions limit established for each emissions averaging group for the 12-month compliance period using Equation 1 of this section.

$$AvH = \frac{\sum_{i=1}^{n} H_i}{\sum_{i=1}^{n} V_i} \qquad \text{(Eq. 1)}$$

Where:

AvH = Total Hg emitted for the 12-month compliance period, lb/MWh or lb/MMBtu;

H_i = Total mass of measured Hg from AvEL emissions averaging group i during the 12-month compliance period, lb;

V_i = Total volume of production from AvEL emissions averaging group i during 12-month compliance period, gross MWh generated or MMBtu heat input to the electric utility steam generating unit; and

n = Number of emission sources in the emissions averaging group or number of emission averaging groups.

(c) If your affected electric utility steam generating unit is also a cogeneration unit, you must use the procedures in paragraphs (c)(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 MWe unit output must use equivalents found in 40 CFR part 60.40(a)(1) for electric utilities (*i.e.*, 250 million Btu/hr input to an electric utility steam generating unit is equivalent to 73 MWe input to the electric utility steam generating unit); 73 MWe input to the electric utility steam generating unit is equivalent to 25 MWe 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 MWe output from the electric utility steam generating unit).

(2) You must use the Equation 2 of this section to determine the cogeneration Hg or Ni emission rate over a specific compliance period.

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

Where:

ER_{cogen} = Cogeneration Hg or Ni emission rate over a compliance period in lb/MWh (or lb Hg/TBtu);

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

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

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

(d) If your coal-fired electric utility steam generating unit is subject to an Hg limit in § 63.9990, you must determine initial compliance according to the applicable requirements in paragraphs (d)(1) through (4) of this section.

(1) Begin compliance monitoring on the effective date of this subpart.

(2) If you use a CEMS, determine the 12-month rolling average Hg emission rate according to the applicable procedures in paragraphs (d)(2)(i) through (iii) of this section.

(i) Calculate the total mass of Hg emissions over a month (M), in micrograms (μg), using Equation 3 of this section.

$$M = \int_0^t C(t)V(t)dt \qquad \text{(Eq. 3)}$$

Where:

M = Total mass of Hg emissions, (μg);

C = Concentration of Hg recorded by CEMS per Performance Specification 12A, micrograms per dry standard cubic meter (μg/dscm);

V = Volumetric flow rate recorded at the same frequency as the CEMS reading for the Hg concentration indicated in Performance Specification 12A, cubic meters per hour (dscm/hr); and

t = total time period over which mass measurements are collected, (hr).

(ii) Calculate the Hg emission rate for an input-based limit (lb/TBtu) using Equation 4 of this section.

$$ER = \frac{M \times \text{conversion factor}}{TP} \qquad \text{(Eq. 4)}$$

Where:

ER = Hg emission rate, (lb/TBtu);

M = Total mass of Hg emissions, micrograms (μg);

Conversion factor = $2.205 \times 10^{\text{minus;9}}$, used to convert micrograms to pounds; and

$TP_{input\text{-}based}$ = Total power, (TBtu).

(iii) Calculate the Hg emission rate for an output-based limit (lb/MWh) using Equation 5 of this section:

$$ER = \frac{M \times \text{conversion factor}}{TP_{output\text{-}based}} \qquad \text{(Eq. 5)}$$

Where:

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

M = Total mass of Hg emissions, (μg);

Conversion factor = $2.205 \times 10^{\text{minus;9}}$; and

$TP_{output\text{-}based}$ = Total power, megawatt-hours (MWh).

(3) If you use Method 324 (40 CFR part 63, appendix A), determine the 12-month rolling average Hg emission rate according to the applicable procedures in paragraphs (d)(3)(i) through (v) of this section.

(i) Sum the Hg concentrations for the emission rate period, (μg/dscm).

(ii) Calculate the total volumetric flow for the emission rate period, (dscm).

(iii) Multiply the total Hg concentration times the total volumetric flow to obtain the total mass of Hg for the emissions rate period in micrograms.

(iv) Calculate the Hg emissions rate for an input-based limit (lb/TBtu) using Equation 4 of this section.

(v) Calculate the Hg emissions rate for an output-based limit (lb/MWh) using Equation 5 of this section.

(4) Report the 12-month rolling average Hg emissions rate in the first semiannual compliance report.

(e) If your oil-fired unit is subject to a Ni emissions limit in § 63.9991, you must determine initial compliance using the applicable procedures in paragraphs (e)(1) through (3) of this section.

(1) Begin compliance monitoring on the effective date of this subpart.

(2) Use the applicable procedures in paragraphs (e)(2)(i) through (v) of this section to convert the Method 29 Ni measurement to the selected format.

(i) Sum the Ni concentrations obtained from the Method 29 test runs, milligrams per dscm (mg/dscm).

(ii) Calculate the total volumetric flow obtained during the Method 29 test runs, (dscm).

(iii) Multiply the total Ni concentration times the total volumetric flow for the duration of the initial compliance testing period to obtain the total mass of Ni in milligrams.

(iv) Calculate the input-based Ni emissions rate in a lb/TBtu format using Equation 6 of this section.

$$ER = \frac{M \times \text{conversion factor}}{TP_{input\text{-}based}} \qquad \text{(Eq. 6)}$$

Where:

ER = Ni emissions rate, (lb/TBtu);

M = Total mass of Ni emissions, (mg);

Conversion factor = 2.205×10^{-6}, used to convert milligrams to pounds; and

$TP_{input\text{-}based}$ = Total power, (TBtu).

(v) Calculate the output-based Ni emissions rate in a lb/MWh format using Equation 7 of this section.

$$ER = \frac{M \times \text{conversion factor}}{TP_{output\text{-}based}} \qquad \text{(Eq. 7)}$$

Where:

ER = Ni emissions rate, (lb/MWh);

M = Total mass of Ni emissions, (mg);

Conversion factor = 2.205×10^{-6} and

$TP_{output\text{-}based}$ = Total power, (MWH).

(f) You must submit the Notification of Compliance Status report containing the results of the initial compliance demonstration according to the requirements in § 63.10030(e).

Continuous Compliance Requirements

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(b) You may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities, in data averages and calculations used to report emission or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(c) A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

§ 63.10021 How do I demonstrate continuous compliance with the emissions limitations?

(a) You must demonstrate continuous compliance with each emission limitation that applies to you according to the methods specified in Table 3 to this subpart.

(b) During periods of startup, shutdown, and malfunction, you must operate in accordance with the startup, shutdown, and malfunction plan as required in § 63.10000(f).

(c) Consistent with §§ 63.6(e) and 63.7(e)(1), deviations that occur during

a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with the startup, shutdown, and malfunction plan. The Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in § 63.6(e).

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.6(h)(4) and (5), 63.7(b) and (c), 63.8(e), 63.8(f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified. Except as provided in paragraph (f) of this section, if you comply with the requirements in § 63.9991(b) for switching fuel, you must notify the Administrator in writing at least 30 days prior to using a fuel other than distillate oil.

(b) As specified in § 63.9(b)(2), if you operate an affected source before [DATE OF PUBLICATION OF THE FINAL RULE IN THE **Federal Register**], you must submit an Initial Notification not later than 120 days after [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**]. The Initial Notification must include the information required in paragraphs (b)(1) through (4) of this section, as applicable.

(1) The name and address of the owner or operator;

(2) The address (*i.e.*, physical location) of the affected source;

(3) An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date;

(4) A brief description of the nature, size, design and method of operation of the source and an identification of the types of emission points within the affected source subject to the requirements and the Hg or Ni pollutant being emitted.

(c) If you startup your new or reconstructed affected source on or after [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**], you must submit an Initial Notification not later than 120 days after you become subject to this subpart. The Initial Notification must include the information required in paragraphs (c)(1) through (4) of this section, as applicable.

(1) The name and address of the owner or operator;

(2) The address (*i.e.*, physical location) of the affected source;

(3) An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date;

(4) A brief description of the nature, size, design and method of operation of the source and an identification of the types of emission points within the affected source subject to the requirements and the Hg or Ni pollutant being emitted.

(d) If you are required to conduct a performance test, you must submit a notification of intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(e) If you are required to conduct a performance test or other initial compliance demonstration as specified in § 63.10007, you must submit a Notification of Compliance Status report according to § 63.9(h)(2)(ii) and the requirements specified in paragraphs (e)(1) through (3) of this section.

(1) For each initial compliance demonstration, you must submit the Notification of Compliance Status report, including all performance test results, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to § 63.10(d)(2).

(2) The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(2)(i) through (iv) of this section, as applicable.

(i) A description of the affected source(s) including identification of which subcategory the source is in, the capacity of the source, a description of the add-on controls used on the source description of the fuel(s) burned, and justification for the worst-case fuel burned during the performance test.

(ii) Summary of the results of all performance tests, fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.

(iii) A signed certification that you have met all applicable emissions limitations, including any emission limitation for an emissions averaging group.

(iv) If you had a deviation from any emission limitation, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(f) If you comply with the requirements in § 63.9991(b) by using distillate fuel, and you must switch fuel because of an emergency, you must notify the Administrator in writing within 30 days of using a fuel other than distillate oil.

§ 63.10031 What reports must I submit and when?

(a) Compliance report due dates. Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit a semiannual compliance report to the permitting authority according to the requirements in paragraphs (a)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.9983 and ending on June 30 or December 31, whichever date comes first after the compliance date that is specified for your affected source in § 63.9983.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after the first compliance report is due.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (a)(1) through (4) of this section.

(b) Compliance report contents. The compliance report must contain the information required in paragraphs (b)(1) through (5) of this section and, as applicable, paragraphs (b)(6) through (10) of this section.

(1) Company name and address.

(2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.

(5) If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in § 63.10(d)(5)(i).

(6) If there are no deviations from any emission limitation (emissions limit or operating limit) in this subpart that apply to you, a statement that there were no deviations from the emissions limitations during the reporting period.

(7) If there were no periods during which a CMS, including CEMS or CPMS, was out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS were out-of-control during the reporting period.

(8) For each deviation from an emission limitation (emissions limit or operating limit) in this subpart that occurs at an affected source where you are not using a CMS to comply with that emission limitation, the compliance report must contain the information in paragraphs (b)(8)(i) through (iii) of this section. This includes periods of startup, shutdown, and malfunction.

(i) The total operating time of each affected source during the reporting period.

(ii) Information on the number, duration, and cause of the deviation (including unknown cause) as applicable and the corrective action taken.

(iii) A copy of the test report if the annual performance test showed a deviation from the Ni emissions limit or a deviation from the Hg emissions limit.

(9) For each deviation from an emission limitation (emissions limit or operating limit) in this subpart occurring at an affected source where you are using a CMS to comply with that emission limitation, you must include the information in paragraphs (b)(9)(i) through (xii) of this section. This includes periods of startup, shutdown, and malfunction and any deviations from your unit-specific monitoring plan as required in § 63.10000(c).

(i) The date and time that each malfunction started and stopped and description of the nature of the deviation (*i.e.*, what you deviated from).

(ii) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(iii) The date, time, and duration that each CMS was out-of-control, including the information in § 63.8(c)(8).

(iv) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(v) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(vi) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(vii) A summary of the total duration of CMS downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(viii) An identification of each parameter that was monitored at the affected source for which there was a deviation, including opacity, carbon monoxide, and operating parameters for wet scrubbers and other control devices.

(ix) A brief description of the source for which there was a deviation.

(x) A brief description of each CMS for which there was a deviation.

(xi) The date of the latest CMS certification or audit for the system for which there was a deviation.

(xii) A description of any changes in CMS, processes, or controls since the last reporting period for the source for which there was a deviation.

(10) A statement that each emissions averaging group was in compliance with its applicable limit during the semiannual reporting period.

(c) Immediate startup, shutdown, and malfunction report. If you had a startup, shutdown, or malfunction during the semiannual reporting period that was not consistent with your SSMP, you must submit an immediate startup, shutdown, and malfunction report according to the requirements of § 63.10(d)(5)(ii).

(d) Part 70 monitoring report. Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limitation (including any operating limit), submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permitting authority.

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) through (3) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) The records in § 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

(b) For each monitoring system required by this subpart, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 3 to this subpart including records of all monitoring data to show continuous compliance with each emission limitation that applies to you.

§ 63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records offsite for the remaining 3 years.

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?

Table 4 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. Environmental Protection Agency (U.S. EPA), or a delegated authority such as your State, local, or tribal agency. If the Administrator has delegated authority to your State, local, or tribal agency, then that agency has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority to this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator and are not transferred to the State, local, or tribal agency. The U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(c) The authorities that will not be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (5) of this section.

(1) Approval of alternatives to the non-opacity emission limits in 63.9990(a) through (g) under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

(5) Approval of the unit-specific monitoring plan under § 63.10000(c).

§ 63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2, and in this section as follows:

Anthracite coal means solid fossil fuel classified as anthracite coal by ASTM Designation D388–77, 90, 91, 95, or 98a (incorporated by reference—see 40 CFR 60.17).

Bituminous coal means solid fossil fuel classified as bituminous coal by ASTM D388–77, 90, 91, 95, or 98a (incorporated by reference—see 40 CFR 60.17).

Coal means all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM Designation D388–77, 90, 91, 95, or 98a (incorporated by reference—see 40 CFR 60.17).

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.*, culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

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. Examples of supplemental fuels include, but are not limited to, petroleum coke and tire-derived fuels.

Combined-cycle gas turbine means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limitation (including any operating limit) or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation (including any operating limit) or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396–78, 89, 90, 92, 96, or 98, Standard Specifications for Fuel Oils (incorporated by reference—see 40 CFR 60.17).

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

Electrostatic precipitator 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.

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 §§ 51.18 and 51.24.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Integrated gasification combined cycle (IGCC) electric utility steam generating unit 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.

Lignite means solid fossil fuel classified as lignite coal by ASTM D388–77, 90, 91, 95, or 98a (incorporated by reference—see 40 CFR 60.17).

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Oil-fired electric utility steam generating unit means an electric utility steam generating unit that either burns oil exclusively, or burns oil alternately with burning fuels other than oil at other times.

Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396–78, Standard Specifications for Fuel Oils (incorporated by reference—see 40 CFR 60.17).

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

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel fired steam generators associated with combined-cycle gas turbines; nuclear steam generators are not included).

Subbituminous coal means solid fossil fuel 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 (incorporated by reference—see 40 CFR 60.17).

Tables to Subpart UUUUU of Part 63

As stated in § 63.10007, you must comply with the following requirements for performance tests:

TABLE 1 TO SUBPART UUUUU OF PART 63.—PERFORMANCE TEST REQUIREMENTS FOR Ni AND Hg

For each affected source . . .	You must . . .	Using this method . . .	According to the following requirements . . .
1. Subject to Ni emissions limit	a. Select sampling port locations and number of traverse points in each stack or duct.	Method 1 or 1A (40 CFR part 60, appendix A).	Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.
	b. Determine the volumetric flow rate of the stack gas.	Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A).	
	c. Determine the dry molecular weight of the stack gas.	Method 3A or 3B (40 CFR part 60, appendix A).	
	d. Determine the moisture content of the stack gas.	Method 4 (40 CFR part 60, appendix A).	
	e. Determine the Ni concentration	Method 29 (40 CFR part 60, appendix A) for Ni.	
2. Subject to Ni emissions limit and that use an ESP.	Establish operating limits for minimum voltage and secondary current or total power input.	Data from the current and voltage monitors for the ESP and the Ni performance test.	(1) Collect secondary current and voltage or total power input for the ESP every 15 minutes during the entire period of the three-run Ni performance test. (2) Determine the average secondary current and voltage or total power input by computing the average of all 15 minute readings taken during each test run. You must set the minimum operating limits equal to the minimum 1-hour average values measured during the three-run performance test.

As stated in § 63.10009, you must show initial compliance with the emissions limitations according to the following:

TABLE 2 TO SUBPART UUUUU OF PART 63.—INITIAL COMPLIANCE WITH EMISSIONS LIMITATIONS FOR Ni AND Hg

For . . .	That is controlled with . . .	You have demonstrated initial compliance if . . .
1. Each oil-fired unit subject to a Ni emissions limit in § 63.9991.	Electrostatic precipitator (ESP)	i. The average Ni emissions in lb/TBtu or lb/MWH over the three-run performance test do not exceed the applicable emissions limit. ii. You have a record of the average secondary current and voltage or total power input of the ESP for each test run over the three-run performance test during which the Ni emissions did not exceed the applicable limit.
2. Each oil-fired unit subject to alternative standard in § 63.9991(b) for fuel switching.	Any type	i. You submit a signed certification in the Notification of Compliance Status report that you burn only distillate oil as the fuel in your unit. ii. You have records demonstrating that you burn only distillate oil as the fuel in your unit.
3. Each coal-fired unit subject to Hg emissions limit in § 63.9990.	Any	You have established a site specific Hg limit according to the procedures in § 63.10009 and reported the limit in your Notification of Compliance Status.

As stated in § 63.10021, you must show continuous compliance with the emissions limitations according to the following:

TABLE 3 TO SUBPART UUUUU OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSIONS LIMITATIONS FOR Hg AND Ni

For . . .	That is controlled with . . .	You must demonstrate continuous compliance by . . .
i. Each unit subject to Hg emissions limit in § 63.9990.	Any type	i. Continuously monitoring the hourly average Hg emissions using a CEMS or monitoring and recording the Hg measurements by semicontinous method. ii. Collecting and reducing the monitoring data according to § 63.100.20. iii. Calculating for each month the monthly rolling average emissions. iv. Maintaining the 12-month rolling average at or below the applicable limit.
2. Each unit subject to Ni limit in § 63.9991	Electrostatic precipitator	i. Collecting and reducing the secondary current and voltage (or total power input) monitoring data. ii. Maintaining the hoursly average secondary current and voltage or total power input at or above the limits established in the performance test. iii. Conducting performance tests at least once per year and reporting the results in the semiannual compliance report.
3. Each unit subject to alternative standard for distillate fuel switching in § 63.9991(b).	Any type	i. Submitting written certifications with each semiannual compliance report according to the requirements in § 63.10031(b) and keeping records of fuel burned to document compliance. ii. Notifying the Adminsitrator if resume burning fuel other than distillate oil according to the requirements in § 63.10030(a). iii. If at any time the unit does not meet the alternative limit, the owner or operator must immediately comply with the applicable Ni limit, including all initial and continuous compliance requirements.

As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU

Citation	Subject	Brief description	Comments
§ 63.1	Applicability	Initial Applicability Determination; Applicability After Standard Established; Permit Requirements; Extensions, Notifications.	Yes.
§ 63.2	Definitions	Definitions for part 63 standards	Yes.
§ 63.3	Units and Abbreviations	Units and abbreviations for part 63 standards.	Yes.
§ 63.4	Prohibited Activities	Prohibited Activities; Compliance date; Circumvention, Severability.	Yes.
§ 63.5	Construction/Reconstruction	Applicability; applications; approvals	Yes.
§ 63.6(a)	Applicability	GP apply unless compliance extension and GP apply to area sources that become major.	Yes.
§ 63.6(b)(1)–(4)	Compliance Dates for New and Reconstructed sources.	Standards apply at effective date; 3 years after effective date; upon start-up; 10 years after construction or reconstruction commences for 112(f).	Yes.
§ 63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal.	Yes.
§ 63.6(b)(6)	[Reserved].		

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major.	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source.	Yes.
§ 63.6(c)(1)–(2)	Compliance Dates for Existing Sources	Comply according to date in subpart, which must be no later than 3 years after effective date and for 112(f) standards, comply within 90 days of effective date unless compliance extension.	Yes.
§ 63.6(c)(3)–(4)	[Reserved].		
§ 63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major.	Area sources that become major must comply with major source standards by date indicated in subpart or by equivalent time period (for example, 3 years).	Yes.
§ 63.6(d)	[Reserved].		
§ 63.6(e)(1)–(2)	Operation & Maintenance	Operate to minimize emissions at all times. AND Correct malfunctions as soon as practicable AND Operation and maintenance requirements independently enforceable information Administrator will use to determine if operation and maintenance requirements were met	Yes.
§ 63.6(e)(3)	Startup, Shutdown, and Malfunction Plan (SSMP).	Requirement for SSM and startup, shutdown, malfunction plan. Content of SSMP	Yes.
§ 63.6(f)(1)	Compliance Except During SSM	Comply with emission standards at all times except during SSM.	Yes.
§ 63.6(f)(2)–(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection.	Yes.
§ 63.6(g)(1)–(3)	Alternative Standard	Procedures for getting an alternative standard.	Yes.
§ 63.6(h)(1)	Compliance with Opacity/VE Standards	Comply with opacity/VE emissions limitations at all times except during SSM.	No.
§ 63.6(h)(2)(i)	Determining Compliance with Opacity/Visible Emission (VE) Standards.	If standard does not state test method, use Method 9 for opacity and Method 22 for VE.	No.
§ 63.6(h)(2)(ii)	[Reserved].		
§ 63.6(h)(2)(iii)	Using Previous Tests to Demonstrate Compliance with Opacity/VE Standards.	Criteria for when previous opacity/VE testing can be used to show compliance with this rule.	No.
§ 63.6(h)(3)	[Reserved].		
§ 63.6(h)(4)	Notification of Opacity/VE Observation Date.	Notify Administrator of anticipated date of observation.	No.
§ 63.6(h)(5)(i), (iii)–(v)	Conducting Opacity/VE Observations	Dates and Schedule for conducting opacity/VE observations.	No.
§ 63.6(h)(5)(ii)	Opacity Test Duration and Averaging Times.	Must have at least 3 hours of observation with thirty, 6-minute averages.	No.
§ 63.6(h)(6)	Records of Conditions During Opacity/VE observations.	Keep records available and allow Administrator to inspect.	No.
§ 63.6(h)(7)(i)	Report continuous opacity monitoring system data monitoring data from performance test.	Submit continuous opacity monitoring system data with other performance test.	No.
§ 63.6(h)(7)(ii)	Using continuous opacity monitoring system instead of Method 9.	Can submit continuous opacity monitoring system data instead of Method 9 results even if rule requires Method 9, but must notify Administrator before performance test.	No.
§ 63.6(h)(7)(iii)	Averaging time for continuous opacity monitoring system during performance test.	To determine compliance, must reduce continuous opacity monitoring system data to 6-minute averages.	No.

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.6(h)(7)(iv)	Continuous opacity monitoring system requirements.	Demonstrate that continuous opacity monitoring system performance evaluations are conducted according to §§ 63.8(e), continuous opacity monitoring system are properly maintained and operated according to 63.8(c) and data quality as § 63.8(d).	No.
§ 63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards.	Continuous opacity monitoring system is probative but not conclusive evidence of compliance with opacity standard, even if Method 9 observation shows otherwise. Requirements for continuous opacity monitoring system to be probative evidence-proper maintenance, meeting PS 1, and data have not been altered.	No.
§ 63.6(h)(8)	Determining Compliance with Opacity/VE Standards.	Administrator will use all continuous opacity monitoring system, Method 9, and Method 22 results, as well as information about operation and maintenance to determine compliance.	No.
§ 63.6(h)(9)	Adjusted Opacity Standard	Procedures for Administrator to adjust an opacity standard.	No.
§ 63.6(i)(1)–(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension.	Yes.
§ 63.6(j)	Presidential Compliance Exemption	President may exempt source category from requirement to comply with rule.	Yes.
§ 63.7(a)(1)	Performance Test Dates	Dates for Conducting Initial Performance Testing and Other Compliance Demonstrations.	Yes.
§ 63.7(a)(2)(i)	Performance Test Dates	New source with initial startup date before effective date has 180 days after effective date to demonstrate compliance.	Yes.
§ 63.7(a)(2)(ii)	Performance Test Dates	New source with initial startup date after effective date has 180 days after initial startup date to demonstrate compliance.	Yes.
§ 63.7(a)(2)(iii)	Performance Test Dates	Existing source subject to standard established pursuant to 112(d) has 180 days after compliance date to demonstrate compliance. AND Existing source with startup date after effective date has 180 days after startup to demonstrate compliance.	Yes. Yes.
§ 63.7(a)(2)(iv)	Performance Test Dates	Existing source subject to standard established pursuant to 112(f) has 180 days after compliance date to demonstrate compliance.	No.
§ 63.7(a)(2)(v)	Performance Test Dates	Existing source that applied for extension of compliance has 180 days after termination date of extension to demonstrate compliance.	Yes.
§ 63.7(a)(2)(vi)	Performance Test Dates	New source subject to standard established pursuant to 112(f) that commenced construction after proposal date of 112(d) standard but before proposal date of 112(f) standard, has 180 days after compliance date to demonstrate compliance.	No.
§ 63.7(a)(2)(vii–viii)	[Reserved].		

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.7(a)(2)(ix)	Performance Test Dates	New source that commenced construction between proposal and promulgation dates, when promulgated standard is more stringent than proposed standard, has 180 days after effective date or 180 days after startup of source, whichever is later, to demonstrate compliance. AND If source initially demonstrates compliance with less stringent proposed standard, it has 3 years and 180 days after the effective date of the standard or 180 days after startup of source, whichever is later, to demonstrate compliance with promulgated standard.	Yes.
§ 63.7(a)(3)	Section 114 Authority	Administrator may require a performance test under Act Section 114 at any time.	Yes.
§ 63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test.	Yes.
§ 63.7(b)(2)	Notification of Rescheduling	If rescheduling a performance test is necessary, must notify Administrator 5 days before scheduled date of rescheduled date.	Yes.
§ 63.7(c)	Quality Assurance/Test Plan	Requirement to submit unit specific test plan 60 days before the test or on date Administrator agrees with: Test plan approval procedures AND Performance audit requirements AND Internal and External QA procedures for testing	Yes.
§ 63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
§ 63.7(e)(1)	Conditions for Conducting Performance Tests.	Perfomance tests must be conducted under representative conditions. AND Cannot conduct performance tests during SSMs. AND Not a deviation to exceed standard during SSM AND Upon request of Administrator, make available records necessary to determine conditions of performance tests.	Yes. Yes. Yes. Yes.
§ 63.7(e)(2)	Conditions for Conducting Performance Tests.	Must conduct according to rule and EPA test methods unless Administrator approves alternative.	Yes.
§ 63.7(e)(3)	Test Run Duration	Must have three separate test runs AND Compliance is based on arithmetic mean of three runs AND Conditions when data from an additional test run can be used	Yes.
§ 63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an alternative test method.	Yes.
§ 63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report. AND Must submit performance test data 60 days after end of test with the Notification of Compliance Status AND Keep data for 5 years	Yes.
§ 63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test.	Yes.

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.7(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard.	Yes.
§ 63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of part 60 apply.	Yes.
§ 63.8(a)(3)	[Reserved].		
§ 63.8(a)(4)	Monitoring with Flares	Unless your rule says otherwise, the requirements for flares in § 63.11 apply.	No.
§ 63.8(b)(1)(i)–(ii)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative.	Yes.
§ 63.8(b)(1)(iii)	Monitoring	Flares not subject to this section unless otherwise specified in relevant standard.	No.
§ 63.8(b)(2)–(3)	Multiple Effluents and Multiple Monitoring Systems.	Specific requirements for installing monitoring systems. AND Must install on each effluent before it is combined and before it is released to the atmosphere unless Administrator approves otherwise. AND If more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup.	Yes.
§ 63.8(c)(1)	Monitoring System Operation and Maintenance.	Maintain monitoring system in a manner consistent with good air pollution control practices.	Yes.
§ 63.8(c)(1)(i)	Routine and Predictable SSM	Follow the SSM plan for routine repairs. Keep parts for routine repairs readily available. Reporting requirements for SSM when action is described in SSM plan.	Yes.
§ 63.8(c)(1)(ii)	SSM not in SSMP	Reporting requirements for SSM when action is not described in SSM plan.	Yes.
§ 63.8(c)(1)(iii)	Compliance with Operation and Maintenance Requirements.	How Administrator determines if source complying with operation and maintenance requirements. AND Review of source O&M procedures, records, Manufacturer's instructions, recommendations, and inspection of monitoring system.	Yes.
§ 63.8(c)(2)–(3)	Monitoring System Installation	Must install to get representative emission and parameter measurements. AND Must verify operational status before or at performance test.	Yes.
§ 63.8(c)(4)	Continuous Monitoring System (CMS) Requirements.	Continuous monitoring systems must be operating except during breakdown, out-of-control, repair, maintenance, and high-level calibration drifts.	Yes.
§ 63.8(c)(4)(i)	Continuous Monitoring System (CMS) Requirements.	Continuous opacity monitoring system must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period.	No.
§ 63.8(c)(4)(ii)	Continuous Monitoring System (CMS) Requirements.	Continuous emissions monitoring system must have a minimum of one cycle of operation for each successive 15-minute period.	Yes.
§ 63.8(c)(7)–(8)	Continuous monitoring systems Requirements.	Out-of-control periods, including reporting.	Yes.

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.8(d)	Continuous monitoring systems Quality Control.	Requirements for continuous monitoring systems quality control, including calibration, etc. AND Must keep quality control plan on record for the life of the affected source. Keep old versions for 5 years after revisions.	Yes.
§ 63.8(e)	Continuous monitoring systems Performance Evaluation.	Notification, performance evaluation test plan, reports.	Yes.
§ 63.8(f)(1)–(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring.	Yes.
§ 63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system.	No.
§ 63.8(g)(1)–(4)	Data Reduction	Continuous emissions monitoring system 1-hour averages computed over at least 4 equally spaced data points.	Yes.
§ 63.8(g)(5)	Data Reduction	Data that cannot be used in computing averages for continuous emissions monitoring system and continuous opacity monitoring system.	No.
§ 63.9(a)	Notification Requirements	Applicability and State Delegation	Yes.
§ 63.9(b)(1)–(5)	Initial Notifications	Submit notification 120 days after effective date. AND Notification of intent to construct/reconstruct AND Notification of commencement of construct/reconstruct; Notification of start-up. AND Contents of each	Yes.
§ 63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed BACT/LAER.	Yes.
§ 63.9(d)	Notification of Special Compliance Requirements for New Source.	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date.	Yes.
§ 63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	Yes.
§ 63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.
§ 63.9(g)	Additional Notifications When Using Continuous Monitoring Systems.	Notification of performance evaluation AND Notification that exceeded criterion for relative accuracy	Yes.
§ 63.9(h)(1)–(6)	Notification of Compliance Status	Contents AND Due 60 days after end of performance test or other compliance demonstration When to submit to Federal vs. State authority	Yes.
§ 63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change in when notifications must be submitted.	Yes.
§ 63.9(j)	Change in Previous Information	Must submit within 15 days after the change.	Yes.
§ 63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension. AND When to submit to Federal vs. State authority AND Procedures for owners of more than 1 source	Yes.

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.10(b)(1)	Recordkeeping/Reporting	General Requirements AND Keep all records readily available AND Keep for 5 years	Yes.
§ 63.10(b)(2)(i)–(v)	Records related to Startup, Shutdown, and Malfunction.	Occurrence of each of operation (process equipment). AND Occurrence of each malfunction of air pollution equipment AND Maintenance on air pollution control equipment AND Actions during startup, shutdown, and malfunction	Yes.
§ 63.10(b)(2)(vi) and (x–xi)	Continuous monitoring systems Records.	Malfunctions, inoperative, out-of-control AND Calibration checks AND Adjustments, maintenance	Yes.
§ 63.10(b)(2)(vii)–(ix)	Records	Measurements to demonstrate compliance with emissions limitations. AND Performance test and performance evaluation AND Measurements to determine conditions of performance test and performance evaluations.	Yes.
§ 63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§ 63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test.	Yes.
§ 63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status.	Yes.
§ 63.10(b)(3)	Records	Applicability Determinations	Yes.
§ 63.10(c)(1)–(6), (9)–(15)	Records	Additional Records for continuous monitoring systems.	Yes.
§ 63.10(c)(7)–(8)	Records	Records of excess emissions and parameter monitoring exceedances for continuous monitoring systems.	Yes.
§ 63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§ 63.10(d)(2)	Report of Performance Test Results	When to submit to Federal or State authority.	Yes.
§ 63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	No.
§ 63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension.	Yes.
§ 63.10(d)(5)	Startup, Shutdown, and Malfunction Reports.	Contents and submission	Yes.
§ 63.10(e)(1)–(92)	Additional continuous monitoring systems Reports.	Must report results for each CEM on a unit. AND Written copy of performance evaluation	Yes.
§ 63.10(e)(3)	Reports	Excess Emission Reports	No.
§ 63.10(e)(3)(i–iii)	Reports	Schedule for reporting excess emission and parameter monitor exceedance (now defined as deviations).	No.

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.10(e)(3)(iv–v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedance (now defined as deviations). AND Provision to request semiannual reporting after compliance for one year AND Submit report by 30th day following end of quarter or calendar half AND If there has not been an exceedance or excess emission (now defined as deviations), report contents is a statement that there have been no deviations	No.
§ 63.10(e)(3)(iv–v)	Excess Emissions Reports	Must submit report containing all of the information in § 63.10(c)(5–13), § 63.8(c)(7–8).	No.
§ 63.10(e)(3)(vi–viii)	Excess Emissions Report and Summary Report.	Requirements for reporting excess emissions for continuous monitoring systems (now called deviations).	No.
§ 63.10(e)(4)	Reporting continuous opacity monitoring system data.	Must submit continuous opacity monitoring system data with performance test data.	No.
§ 63.10(f)	Waiver for Recordkeeping Reporting	Procedures for Administrator to waive	Yes.
§ 63.11	Flares	Requirements for flares	No.
§ 63.12	Delegation	State authority to enforce standards	Yes.
§ 63.13	Addresses	Addresses where reports, notifications, and requests are sent.	Yes.
§ 63.14	Incorporation by Reference	Test methods incorporated by reference	Yes.
§ 63.15	Availability of Information	Public and confidential information	Yes.

APPENDIX B—PART 63

7. Appendix B to part 63 is amended by adding in numerical order new Method 324 to read as follows:

Method 324—Determination of Vapor Phase Flue Gas Mercury Emissions From Stationary Sources Using Dry Sorbent Trap Sampling

1.0 Introduction.

This method describes sampling criteria and procedures for the continuous sampling of mercury (Hg) emissions in combustion flue gas streams using sorbent traps. Analysis of each trap can be by cold vapor atomic fluorescence spectrometry (AF) which is described in this method, or by cold vapor atomic absorption spectrometry (AA). Only the AF analytical method is detailed in this method, with reference being made to other published methods for the AA analytical procedure. The Electric Power Research Institute has investigated the AF analytical procedure in the field with the support of ADA–ES and Frontier Geosciences, Inc. The AF procedure is based on EPA Method 1631, Revision E: Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Fluorescence Spectrometry. Persons using this method should have a thorough working knowledge of Methods 1, 2, 3, 4 and 5 of 40 CFR part 60, appendix A.

1.1 Scope and Application.

1.1.1 Analytes. The analyte measured by this method is total vapor-phase Hg, which represents the sum of elemental (CAS Number 7439–97–6) and oxidized forms of Hg, mass concentration (micrograms/dscm) in flue gas samples.

1.1.2 Applicability. This method is applicable to the determination of vapor-phase Hg concentrations ranging from 0.03 µg/dncm to 100 µg/dncm in low-dust applications, including controlled and uncontrolled emissions from stationary sources, only when specified within the regulations. When employed to demonstrate compliance with an emission regulation, paired sampling is to be performed as part of the method quality control procedure. The method is appropriate for flue gas Hg measurements from combustion sources. Very low Hg concentrations will require greater sample volumes. The method can be used over any period from 30 minutes to several days in duration, provided appropriate sample volumes are collected and all the quality control criteria in Section 9.0 are met. When sampling for periods greater than 12 hours, the sample rate is required to be maintained at a constant proportion to the total stack flowrate, ±25 percent to ensure representativeness of the sample collected.

2.0 Summary of Method.

Known volumes of flue gas are extracted from a duct through a single or paired sorbent traps with a nominal flow rate of 0.2 to 0.6 liters per minute through each trap. Each trap is then acid leached and the resulting leachate is analyzed by cold vapor atomic fluorescence spectrometry (CVAFS) detection. The AF analytical procedure is described in detail in EPA Method 1631. Analysis by AA can be performed by existing recognized procedures, such as that contained in ASTM Method D6784–02 (incorporated by reference, see § 63.14) or EPA Method 29.

3.0 Definitions. [Reserved]

4.0 Clean Handling and Contamination.

During preparation of the sorbent traps, as well as transport, field handling, sampling, recovery, and laboratory analysis, special attention must be paid to cleanliness procedures. This is to avoid Hg contamination of the samples, which generally contain very small amounts of Hg. For specifics on how to avoid contamination, Section 4 of Method 1631 should be well understood.

5.0 Safety.

5.1 Site hazards must be prepared for in advance of applying this method in the field. Suitable clothing to protect against site hazards is required, and requires advance coordination with the site to understand the conditions and applicable safety policies. At a minimum, portions of the sampling system will be hot, requiring appropriate gloves, long sleeves, and caution in handling this equipment.

5.2 Laboratory safety policies are to minimize risk of chemical exposure and to properly handle waste disposal. Personnel will don appropriate laboratory attire according to a Chemical Hygiene Plan established by the laboratory. This includes, but is not limited to, laboratory coat, safety goggles, and nitrile gloves under clean gloves.

5.3 The toxicity or carcinogenicity of reagents used in this method has not been fully established. The procedures required in this method may involve hazardous materials, operations, and equipment. This method 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. Each chemical should be regarded as a potential health hazard and exposure to these compounds should be minimized. Chemists should refer to the MSDS for each chemical with which they are working.

5.4 Any wastes generated by this procedure must be disposed of according to a hazardous materials management plan that details and tracks various waste streams and disposal procedures.

6.0 Equipment and Supplies.

6.1 Hg Sampling Train. A Schematic of a single trap sampling train used for this method is shown in Figure 324–1. Where this method is used to collect data to demonstrate compliance with a regulation, it must be performed with paired sorbent trap equipment.

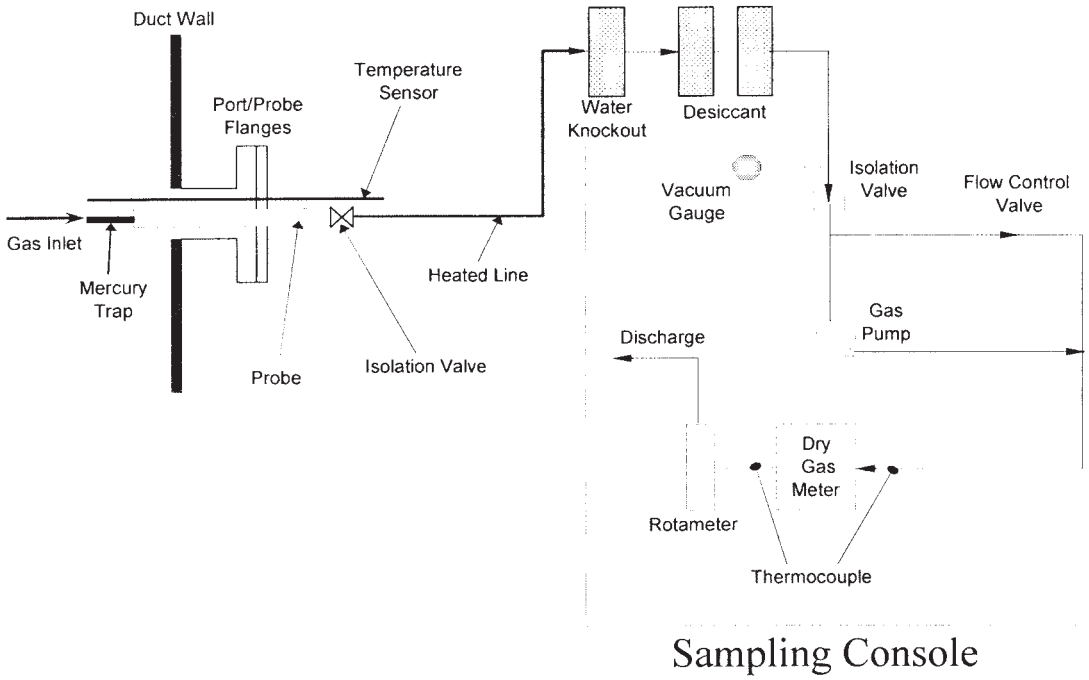


Figure 324–1. Hg Sampling Train Illustrating Single Trap.

6.1.1 Sorbent Trap. Use sorbent traps with separate main and backup sections in series for collection of Hg. Selection of the sorbent trap shall be based on: (1) Achievement of the performance criteria of this method, and (2) data is available to demonstrate the method can pass the criteria in EPA Method 301 when used in this method and when the results are compared with those from EPA Method 29, EPA Method 101A, or ASTM Method 6784–02 for the measurement of vapor-phase Hg in a similar flue gas matrix. Appropriate traps are referred to as ''sorbent trap'' throughout this method. The method requires the analysis of Hg in both main and backup portions of the sorbent within each trap. The sorbent trap should be obtained from a reliable source that has clean handling procedures in place for ultra low-level Hg analysis. This will help assure the low Hg environment required to manufacture sorbent traps with low blank levels of Hg. Sorbent trap sampling requirements or needed characteristics are shown in Table 324–1. Blank/cleanliness and other requirements are described in Table 324–2. The sorbent trap is supported on a probe and inserted directly into the flue gas stream, as shown on Figure 324–1. The sampled sorbent trap is the entire Hg sample.

6.1.2 Sampling Probe. The probe assembly shall have a leak-free attachment to the sorbent trap. For duct temperatures from 200 to 375°F, no heating is required. For duct temperatures less than 200°F, the sorbent tube must be heated to at least 200°F or higher to avoid liquid condensation in the sorbent trap by using a heated probe. For duct temperatures greater than 375°F, a large sorbent trap must be used, as shown in Table 324–1, and no heating is required. A thermocouple is used to monitor stack temperature.

6.1.3 Umbilical Vacuum Line. A 250°F heated umbilical line shall be used to convey to the moisture knockout the sampled gas that has passed through the sorbent trap and probe assembly.

6.1.4 Moisture Knockout. Impingers and desiccant can be combined to dry the sample gas prior to entering the dry gas meter. Alternative sample drying methods are acceptable as long as they do not affect sample volume measurement.

6.1.5 Vacuum Pump. A leak tight vacuum pump capable of delivering a controlled extraction flow rate between 0.1 to 0.8 liters per minute.

6.1.6 Dry Gas Meter. Use a dry gas meter that is calibrated according to the procedures in 40 CFR part 60, appendix A, Method 5, to measure the total sample volume collected. The dry gas meter must be sufficiently accurate to measure the sample volume within 2 percent, calibrated at the selected flow rate and conditions actually encountered during sampling, and equipped with a temperature sensor capable of measuring typical meter temperatures accurately to within 3°C (5.4°F).

6.2 Sample Analysis Equipment. Laboratory equipment as described in Method 1631, Sections 6.3 to 6.7 is required for analysis by AF. For analysis by AA, refer to Method 29 or ASTM Method 6784–02.

TABLE 324–1.—SORBENT TRAP AND SAMPLING REQUIREMENTS.

Item to be determined	Small sorbent trap	Large sorbent trap
Sampling Target: Hg Loading Range, μg	Minimum = 0.025 μg/trap Maximum = 150 μg/trap	Minimum = 0.10 μg/trap Maximum = 1800 μg/trap
Sampling Duration Required: limits on sample times.	Minimum = 30 minutes Maximum = 24 hours	Minimum = 24 hours Maximum = 10 days
Sampling Temperature Required	200 to 375°F	200 to 425°F
Sampling Rate Required	0.2 to 0.6 L/min; start at 0.4 L/min Must be constant proportion within +/− 25% if greater than 12 hours; constant rate within +/− 25 % if less than 12 hours.	0.2 to 0.6 L/min; start at 0.4 L/min Must be constant proportion of stack flowrate within +/− 25%

7.0 Analysis by AF, Reagents and Standards.

For analysis by AF, use Method 1631, Sections 7.1–7.3 and 7.5–7.12 for laboratory reagents and standards. Refer to Method 29 or ASTM Method 6784–02 for analysis by AA.

7.1 Reagent Water. Same as Method 1631, Section 7.1.

7.2 Air. Same as Method 1631, Section 7.2.

7.3 Hydrochloric Acid. Same as Method 1631, Section 7.3.

7.4 Stannous Chloride. Same as Method 1631, Section 7.5.

7.5 Bromine Monochloride (BrCl, 0.01N). Same as Method 1631, Section 7.6.

7.6 Hg Standards. Same as Method 1631, Sections 7.7 to 7.11.

7.7 Nitric Acid. Reagent grade, low Hg.

7.8 Sulfuric Acid. Reagent grade, low Hg.

7.9 Nitrogen. Same as Method 1631, Section 7.12.

7.10 Argon. Same as Method 1631, Section 7.13.

8.0 Sample Collection and Transport.

8.1 Pre-Test.

8.1.1 Site information should be obtained in accordance with Method 1 (40 CFR part 60, appendix A). Identify a location that has been shown to be free of stratification for SO_2 and NO_X through concentration measurement traverses for those gases. An estimation of the expected Hg concentration is required to establish minimum sample volumes. Based on estimated minimum sample volume and normal sample rates for each size trap used, determine sampling duration with the data provided in Table 324–1.

8.1.2 Sorbent traps must be obtained from a reliable source such that high quality control and trace cleanliness are maintained. Method detection limits will be adversely affected if adequate cleanliness is not maintained. Sorbent traps should be handled only with powder-free low Hg gloves (vinyl, latex, or nitrile are acceptable) that have not touched any other surface. The sorbent traps should not be removed from their clean storage containers until after the preliminary leak check has been completed. Field efforts at clean handling of the sorbent traps are key to the success of this method.

8.1.3 Assemble the sample train according to Figure 324–1, except omit the sorbent trap.

8.1.4 Preliminary Leak Check. Perform system leak check without the single or dual sorbent traps in place. This entails plugging the end of the probe to which each sorbent trap will be affixed, and using the vacuum pump to draw a vacuum in each sample train. Adjust the vacuum in the sample train to 15 inches Hg. A rotameter on the dry gas meter will indicate the leakage rate. The leakage rate must be less than 2 percent of the planned sampling rate.

8.1.5 Release the vacuum in the sample train, turn off the pump, and affix the sorbent trap to the end of the probe, using clean handling procedures. Leave the flue gas end of the sorbent trap plugged.

8.1.6 Pre-test Leak Check. Perform a leak check with the Sorbent trap in place. Use the sampling vacuum pump to draw a vacuum in the sample train. Adjust the vacuum in the sample train to 15 inches Hg. A rotameter on the dry gas meter will indicate the leakage rate. Record the leakage rate. The leakage rate must be less than 2 percent of the planned sampling rate. Once the leak check passes this criterion, carefully release the vacuum in the sample train (the sorbent trap must not be exposed to abrupt changes in pressure or to backflow), then re-cap the flue gas end of the sorbent trap until the probe is ready for insertion. The sorbent trap packing beds must be undisturbed by the leak test to prevent gas channeling through the media during sampling.

8.1.7 Use temperature controllers to heat the portions of the trains that require it. The sorbent trap must be maintained between 200 and 375 °F during sampling.

8.1.8 Gas temperature and static pressure must be considered prior to sampling in order to maintain proper safety precautions during sampling.

8.2 Sample Collection.

8.2.1 Remove the plug from the end of a sorbent trap and store it in a clean sorbent trap storage container. Remove the sample duct port cap and insert the probe. Secure the probe and ensure that no leakage occurs between the duct and environment.

8.2.2 Record initial data including the start time, starting dry gas meter readings, and the name of the field tester(s). Set the initial sample flow rate to 0.4 L/min (+/− 25 percent).

8.2.3 For constant-flow sampling (samples less than 12 hours in duration), every 10–15 minutes during the sampling period: record the time, the sample flow rate, the gas meter readings, the duct temperature, the flow meter temperatures, temperatures of heated equipment such as the vacuum lines and the probes (if heated), and the sampling vacuum reading. Adjust the sample rate as needed, maintaining constant sampling within +/− 25 percent of the initial reading.

8.2.4 For constant proportion sampling (samples 12 hours or greater in duration), every hour during the sampling period: record the time, the sample flow rate, the gas meter readings, the duct temperature, the flow meter temperatures, temperatures of heated equipment such as the vacuum lines and the probes (if heated), and the sampling vacuum readings. Also record the stack flow rate reading, whether provided as a CEM flow monitor signal, a pitot probe or other direct flow indication, or a plant input signal. Adjust the sampling rate to maintain proportional sampling within +/− 25 percent relative to the total stack flowrate.

8.2.5 Obtain and record operating data for the facility during the test period, including total stack flowrate and the oxygen concentration at the flue gas test location. Barometric pressure must be obtained for correcting sample volume to standard conditions.

8.2.6 Post Test Leak Check. When sampling is completed, turn off the sample pump, remove the probe from the port and carefully re-plug the end of the sorbent trap. Perform leak check by turning on the sampling vacuum pumps with the plug in place. The rotameter on the dry gas meters will indicate the leakage rates. Record the leakage rate and vacuum. The leakage rate must be less than 2 percent of the actual sampling rate. Following the leak check, carefully release the vacuum in the sample train.

8.2.7 Sample Recovery. Recover each sampled sorbent trap by removing it from the probe, plugging both ends with the clean caps provided with the sorbent trap, and then wiping any dirt off the outside of the sorbent trap. Place the sorbent trap into the clean sample storage container in which it was provided, along with the data sheet that includes the post-test leak check, final volume, and test end time.

8.3 Quality Control Samples and Requirements.

8.3.1 Field blanks. Refer to Table 324–2.

8.3.2 Duplicate (paired or side by side) samples. Refer to Section 8.6.6 of Performance Specification 12A of 40 CFR part 60, appendix B for this criteria.

8.3.3 Breakthrough performance data (''B'' bed in each trap, or second traps behind). Refer to Table 324–2.

8.3.4 Field spikes (sorbent traps spiked with Hg in the lab and periodically sampled in the field to determine overall accuracy). Refer to Table 324–2.

8.3.5 Laboratory matrix and matrix spike duplicates. Refer to Table 324–2.

9.0 Quality Control.

Table 324–2 summarizes the major quantifiable QC components.

TABLE 324–2.—QUALITY CONTROL FOR SAMPLES

QA/QC specification	Acceptance criteria	Frequency	Corrective action
Leak-check	<2% of sampling rate	Pre and post-sampling	Pre-sampling: repair leak. Post-sampling: Flag data and repeat run if for regulatory compliance.
Sample Flow Rate for samples less than 12 hours in duration.	0.4 L/min initially and +/− 25% of initial rate throughout run.	Throughout run every 10–15 minutes.	Adjust when data is recorded.
Sample Flow Rate for samples greater than 12 hours in duration.	0.4 L/min initially and maintain +/− 25% of ratio to flue gas flow rate throughout sampling.	Throughout run every hour	Adjust when data is recorded.
Sorbent trap laboratory blank (same lot as samples).	<5 ng/trap and a standard deviation of <1.0 ng/trap (n=3).	3 per analysis set of 20 sorbent traps.	
Sorbent trap field blank (same lot as samples).	<5 ng/trap and a standard deviation of <1.0 ng/trap (n=3) OR <5% of average sample collected.	1 per every 10 field samples collected.	
B-Trap Bed Analysis	<2% of A-Trap Bed Value OR < 5 ng/trap.	Every sample	
Paired Train Results	Same as Section 8.6.6 of PS–12A of 40 CFR Part 60, Appendix B.		
Field Spikes	80% to 120% recovery	For long-term regulatory monitoring, 1 per every 3 samples for the first 12 samples.	If the first 4 field spikes do not meet the +/− 20% criteria, take corrective sampling and laboratory measures and repeat at the 1 per every 3 sample rate until the +/− 20% criteria is met.
Laboratory matrix and matrix spike duplicates.	85% to 115% recovery	1 per every 10 or 20 samples—to be determined.	

10.0 Calibration and Standards.

Same as Sections 10.1, 10.2 and 10.4 of Method 1631.

10.1 Calibration and Standardization. Same as Sections 10.1 and 10.4 of Method 1631.

10.2 Bubbler System. Same as Section 10.2 of M1631.

10.3 Flow-Injection System. Not applicable.

11.0 Analytical Procedures.

11.1 *Preparation Step.* The sorbent traps are received and processed in a low-Hg environment (class-100 laminar-flow hood and gaseous Hg air concentrations below 20 ng/m^3) following clean-handling procedures. Any dirt or particulate present on the exterior of the trap must be removed to avoid contamination of the sample. The sorbent traps are then opened and the sorbent bed(s) transferred to an appropriate sized trace-clean vessel. It is recommended that the height of the trace-clean vessel be at least 3 times the diameter to facilitate a refluxing action.

11.2 Leaching Step. The sorbent trap is then subjected to a hot-acid leach using a 70:30 ratio mixture of concentrated HNO_3/H_2SO_4. The acid volume must be 40 percent of the expected end volume of the digest after dilution. The HNO_3/H_2SO_4 acid to carbon ratio should be approximately 35:1. The leachate is then heated to a temperature of 50 to 60°C for 1.5 to 2.0 hours in the finger-tight capped vessels. This process may generate significant quantities of noxious and corrosive gasses and must only be performed in a well-ventilated fume hood. Care must be taken to prevent excessive heated leaching of the samples as this will begin to break down the charcoal material.

11.3 Dilution Step. After the leached samples have been removed from the hot plate and allowed to cool to room temperature, they are brought to volume with a 5 percent (v/v) solution of 0.01 N BrCl. As the leaching digest contains a substantial amount of dissolved gasses, add the BrCl slowly, especially if the samples are still warm. As before, this procedure must be performed in a properly functioning fume hood. The sample is now ready for analysis.

11.4 Hg Reduction and Purging. (Reference Section 11.2 of M1631 except that NH2OH is not used.)

11.4.1 Bubbler System. Pipette an aliquot of the digested sample into the bubbler containing pre-blanked reagent water and a soda lime trap connected to the exhaust port. Add stannous chloride ($SnCl_2$) to reduce the aliquot and then seal the bubbler. Connect gold sample traps to the end of the soda lime trap as shown in Figures 1 and 2 of Method 1631. Finally, connect the N_2 lines and purge for 20 minutes. The sample trap can then be added into the analytical train. M1631, Section 11.2.1.

11.4.2 Flow Injection System. If required.

11.5 Desorption of Hg from the gold trap, and peak evaluation. Use Section 11.3 and 11.4 in M1631.

11.6 Instrument Calibration. Analyze the standards by AA or AF following the guidelines specified by the instrument manufacturer. Construct a calibration curve by plotting the absorbances of the standards versus µg/l Hg. The R^2 for the calibration curve should be 0.999 or better. If the curve does not have an R^2 value equal to or better than 0.999 then the curve should be rerun. If the curve still does not meet this criteria then new standards should be prepared and the instrument recalibrated. All calibration points contained in the curve must be within 10 percent of the calibration value when the calibration curve is applied to the calibration standards.

11.7 Sample Analysis. Analyze the samples in duplicate following the same procedures used for instrument calibration. From the calibration curve, determine sample Hg concentrations. To determine total Hg mass in each sample fraction, refer to calculations in Section 15. Record all sample dilutions.

11.8 Continued Calibration Performance. To verify continued calibration performance, a continuing calibration check standard should be run every 10 samples. The measured Hg concentration of the continuing calibration check standard must be within 10 percent of the expected value.

11.9 Measurement Precision. The QA/QC for the analytical portion of this method is that every sample, after it has been prepared, is to be analyzed in duplicate with every tenth sample analyzed in triplicate. These results must be within 10 percent of each other. If this is not the case, then the instrument must be recalibrated and the samples reanalyzed.

11.10 Measurement Accuracy. Following calibration, an independently prepared standard (not from same calibration stock solution) should be analyzed. In addition, after every ten samples, a known spike sample (standard addition) must be analyzed.

The measured Hg content of the spiked samples must be within 10 percent of the expected value.

11.11 Independent QA/QC Checks. It is suggested that the QA/QC procedures developed for a test program include submitting, on occasion, spiked Hg samples to the analytical laboratory by either the prime contractor, if different from the laboratory, or an independent organization. The measured Hg content of reference samples must be within 15 percent of the expected value. If this limit is exceeded, corrective action (*e.g.,* re-calibration) must be taken and the samples re-analyzed.

11.12 Quality Assurance/Quality Control. For this method, it is important that both the sampling team and analytical people be very well trained in the procedures. This is a complicated method that requires a high-level of sampling and analytical experience. For the sampling portion of the QA/QC procedure, both solution and field blanks are required. It should be noted that if high-quality reagents are used and care is taken in their preparation and in the train assembly, there should be little, if any, Hg measured in either the solution or field blanks.

11.13 Solution Blanks. Solution blanks must be taken and analyzed every time a new batch of solution is prepared. If Hg is detected in these solution blanks, the concentration is subtracted from the measured sample results. The maximum amount that can be subtracted is 10 percent of the measured result or 10 times the detection limit of the instrument which ever is lower. If the solution blanks are greater than 10 percent the data must be flagged as suspect.

11.14 Field Blanks. A field blank is performed by assembling a sample train, transporting it to the sampling location during the sampling period, and recovering it as a regular sample. These data are used to ensure that there is no contamination as a result of the sampling activities. A minimum of one field blank at each sampling location must be completed for each test site. Any Hg detected in the field blanks cannot be subtracted from the results. Whether or not the Hg detected in the field blanks is significant is determined based on the QA/QC procedures established prior to the testing. At a minimum, if field blanks exceed 30 percent of the measured value at the corresponding location, the data must be flagged as suspect.

12.0 Calculations and Data Analysis.

Use Section 12 in M1631.

13.0 Constant Proportion Sampling.

Calculate the Sample Rate/Stack Flow = ''x.'' ''X'' must be maintained within 0.75 ''x'' to 1.25 ''x'' for sampling times in excess of 12 hours. For mass emission rate calculations, use the flow CEM total measured flow corresponding to the sorbent trap sample time period.

14.0 Sampling and Data Summary Calculations.

Refer to 40 CFR part 60, appendix A, Methods 2, 4, and 5 for example calculations.

15.0 Pollution Prevention.

Refer to Section 13 in Method 1631.

16.0 Waste Management.

Refer to Section 14 in Method 1631.

17.0 Bibliography.

17.1 EPA Method 1631, Revision E ''Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Fluorescence Spectrometry,'' August 2002.

17.2 ''Comparison of Sampling Methods to Determine Total and Speciated Mercury in Flue Gas,'' CRADA F00–038 Final Report, DOE/NETL–2001/1147, January 4, 2001.

17.3 40 CFR part 60, appendix A, ''Method 29—Determination of Metals Emissions from Stationary Sources.''

17.4 40 CFR part 60, appendix B, ''Performance Specification 12A, Specification and Test Procedures for Total Vapor Phase Mercury Continuous Emission Monitoring Systems in Stationary Sources.''

17.5 ASTM Method D6784–02, ''Standard Test Method for Elemental, Oxidized, Particle-bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method).''

Option 2—Proposed Amendments to Parts 60 and 63

PART 60—[AMENDED]

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

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

2. Section 60.17 is amended by adding paragraph (a)(65) to read as follows:

§ 60.17 Incorporations by Reference.

* * * * *

(a) * * *

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

* * * * *

Subpart Da—[Amended]

3. Subpart Da is amended by:

a. Redesignate § 60.49a as § 60.51a;

b. Redesignate § 60.48a as § 60.50a;

c. Redesignate § 60.47a as § 60.49a;

d. Redesignate § 60.46a as § 60.48a;

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

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

§ 60.45a Standard for Mercury

(a) For each coal-fired electric utility steam generating unit other than an integrated gasification combined cycle (IGCC) electric utility steam generating unit, you must meet each mercury (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 6.0×10^{-6} pound per Megawatt hour (lb/MWh) or 0.0060 lb/gigawatt-hour (GWh) on an output basis. The SI equivalent is 0.00075 nanograms per joule (ng/J).

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal, you must not discharge into the atmosphere any gases from a new affected source which contain Hg 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.

(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 62×10^{-6} lb/MWh or 0.062 lb/GWh on an output basis. The SI equivalent is 0.0078 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 1.1×10^{-6} lb/MWh or 0.0011 lb/GWh on an output basis. The SI equivalent is 0.00087 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 your 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 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.

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

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 that applies to affected source i, lb/MWh.

HH_i = Electricity output from affected source i during the production period related to the corresponding H_i that falls within the compliance period, gross MWh generated by the electric utility steam generating unit.

n = Number of 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, you must not discharge into the atmosphere any gases from a new affected source which contain Hg 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 Standard for Nickel

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, the owner or operator of each oil-fired unit subject to the provisions of this subpart shall not discharge into the atmosphere any gases from an oil-fired electric utility steam generating unit which contain Ni in excess of 0.0008 lb/MWh on an output basis. The SI equivalent is 0.010 ng/J.

(b) The emissions limit for an oil-fired electric utility steam generating unit in paragraph (a) of this section does not apply if the owner or operator uses distillate oil as fuel. Except as noted in paragraph (e) of this section, the emissions limit in paragraph (a) of this section will apply immediately if the owner or operator subsequently uses a fuel other than distillate oil.

(c) If you use an ESP to meet a Ni emissions limit in this subpart, you must operate the ESP such that the hourly average voltage and secondary current (or total power input) do not fall below the limit established in the initial or subsequent performance test.

(d) If you use a control device or combination of control devices other than an ESP to meet the Ni emissions limit, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters for an ESP, you must apply to the Administrator for approval of alternative monitoring under § 60.13(i).

(e) If you comply with the requirements in § 60.46a(b) for switching fuel, and you must switch fuel because of an emergency, you must notify the Administrator in writing within 30 days of using a fuel other than distillate oil.

4. 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; in paragraph (k)(2)(iii) by revising the existing references from ''§ 60.47a(k)'' to ''§ 60.49a(k)''; and in paragraph (k)(2)(iv) by revising the existing references from ''§ 60.47a(l)'' to ''§ 60.49a(l)''; and

f. Adding new paragraphs (m) and (n).

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, the Hg emission standards under § 60.45a, and the Ni emission standards under § 60.46a apply at all times except during periods of startup, shutdown, or malfunction.

* * * * *

(m) *Compliance provisions for sources subject to § 60.45a.* The owner or operator of an affected facility subject to § 60.45a (new sources constructed after January 30, 2004) shall calculate Hg emissions by multiplying the average hourly Hg output concentration measured according to the provisions of § 60.49a(c) by the average hourly flow rate measured according to the provisions of § 60.49a(l) and divided by the average hourly gross heat rate measured according to the provisions in § 60.49a(k).

(n) *Compliance provisions for sources subject to § 60.46a.* (1) The owner or operator of an affected facility subject to § 60.46a(a) (new source constructed after January 30, 2004) shall calculate Ni emissions rate according to the procedures outlined in § 60.50a(i).

5. 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.''

c. Revising paragraph (k) introductory text; and

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

The revision and additions read as follows:

§ 60.49a Emission monitoring.

* * * * *

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine compliance with the output-based standards under §§ 60.42a(c), 60.43a(i), 60.44a(d)(1), 60.44a(e), 60.45a, and 60.46a.

* * * * *

(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 (3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in 40 CFR part 60, appendix B.

(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 40 CFR part 60, appendix B.

(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) Each CEMS must determine and record the 1-hour average emissions using all the hourly averages collected for periods during which the CEMS is not out of control.

(iv) The owner or operator must record the results of each inspection, calibration, and validation check.

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

(i) A complete day of data for continuous monitoring is 18 hours or more in a 24-hour period.

(ii) A complete month of data for continuous monitoring is 21 days or more in a calendar month.

(iii) If you collect less than 21 days of continuous emissions data, you must discard the data collected that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months.

(iv) If you collect less than 21 days per monthly period of continuous data again in that same 12-month rolling average cycle, you must discard the data collected that month and replace that data with the highest individual monthly emission rate determined in the last 12 months.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator must monitor Hg emissions using Method 324 in 40 CFR part 63, appendix A.

(r) The owner or operator of an affected facility which uses an ESP to meet a Ni limit in § 60.46a shall install and operate a continuous parameter monitoring system (CPMS) to measure and record the voltage and secondary current (or total power input) to the control device according to the requirements in paragraphs (r)(1) through (3) of this section.

(1) Each CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. The owner or operator must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Each CPMS must determine the 1-hour block average of all recorded readings.

(3) The owner or operator must record the results of each inspection, calibration, and validation check for a CPMS.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system. 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 CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control 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);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of § 60.13(d);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of § 60.13; and

(6) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 60.7.

6. 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),'' respectively;

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

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

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

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

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

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

Where:

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

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

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

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

(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 owner or operator shall demonstrate compliance by calculating the arithmetic average of all weekly emission rates for Hg for the 12 successive calendar months, except for 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 (ii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in micrograms (μg), using Equation 2 of this section.

$$M = \int_0^t C(t)V(t)dt \qquad \text{(Eq. 2)}$$

Where:

M = Total mass of Hg emissions, (μg);
C = Concentration of Hg recorded by CEMS per Performance Specification 12A (40 CFR part 60, appendix B), micrograms per dry standard cubic meter (μg/dscm);
V = Volumetric flow rate recorded at the same frequency as the CEMS reading for the Hg concentration indicated in PS–12A, cubic meters per hour (dscm/hr); and
t = total time period over which mass measurements are collected, (hr).

(ii) Calculate the Hg emission rate for an output-based limit (lb/hr) using Equation 3 of this section:

$$ER = \frac{M \times \text{conversion factor}}{TP_{\text{output-based}}} \qquad \text{(Eq. 3)}$$

Where:

ER = Hg emission rate, (lb/hr);
M = Total mass of Hg emissions, (μg);
Conversion factor = 2.205×10^{-9}; and
$TP_{\text{output-based}}$ = Total power, megawatt-hours (MWh).

(3) If you use Method 324 (40 CFR part 63, appendix B), determine the 12-month rolling average Hg emission rate according to the applicable procedures in paragraphs (h)(3)(i) through (iv) of this section.

(i) Sum the Hg concentrations for the emission rate period, (μg/dscm).

(ii) Calculate the total volumetric flow rate for the emission rate period, (dscm).

(iii) Multiply the total Hg concentration times the total volumetric rate to obtain the total mass of Hg for the emission rate period in micrograms.

(iv) Calculate the Hg emission rate for an output-based limit (lb/hr) using Equation 3 of this section.

(i) The owner or operator shall determine compliance with the Ni limit in § 60.46a according to the procedures in paragraphs (i)(1) through (2) of this section.

(1) Ni emissions concentration for compliance under § 60.46a is determined by the three-run average (nominal 1-hour runs) by Method 29 of 40 CFR part 60, Appendix A, for the initial and subsequent performance tests.

(2) Use the applicable procedures in paragraphs (2)(i) through (v) of this section to convert the Method 29 Ni emissions measurement to the output-based format for comparison to the § 60.46a Ni emission limit.

(i) Sum the Ni concentrations obtained from the Method 29 test runs, milligrams per dscm (mg/dscm).

(ii) Calculate the total volumetric flow rate obtained during the Method 29 test runs, (dscm).

(iii) Multiply the total Ni concentration times the total volumetric flow rate for the duration of the initial compliance testing period to obtain the total mass of Ni in milligrams.

(iv) Calculate the output-based Ni emissions rate in a lb/ format using Equation 4 of this section.

$$ER = \frac{M \times \text{conversion factor}}{TP_{\text{output-based}}} \qquad \text{(Eq. 4)}$$

Where:

ER = Ni emission rate, (lb/hr);
M = Total mass of Ni emissions, (mg);
Conversion factor = 2.205×10^{-6}; and
$TP_{\text{output-based}}$ = Total power, (MWh).

(3) Compliance with the Ni emission limits under § 60.46a is determined by the three-run average (nominal 1-hour runs) by Method 29 for the initial and subsequent performance tests.

(j) Quarterly accuracy determinations and daily calibration drift tests for gaseous Hg CEMS shall be performed in accordance with Procedure 1 (appendix F of 40 CFR part 60). Annual RATAs for Hg sorbent trap monitoring systems shall also be performed in accordance with Procedure 1.

7. 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.''

The revisions and additions read as follows:

§ 60.51a Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, particulate matter, Hg, and Ni 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.

* * * * *

8. Section 60.52a is added to read as follows:

§ 60.52a Recordkeeping Requirements

The owner or operator of an affected facility subject to the emissions limitations in § 60.45a or § 60.46a shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations.

Subpart GGGG—[Added]

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

Subpart GGGG—Emission Guidelines and Compliance Times for Oil-fired Electric Utility Steam Generating Units

Sec.

60.4000 Scope
60.4005 Definitions
60.4010 Designated Facilities
60.4015 Emission Guidelines for Oil-fired Electric Utility Steam Generating Units
60.4020 Compliance Provisions and Performance Testing
60.4025 Reporting and Recordkeeping Guidelines
60.4030 Compliance Times

§ 60.4000 Scope

This subpart contains emission guidelines and compliance times for the control of certain designated pollutants from certain designated electric utility steam generating units in accordance with section 111(d) of the Act and subpart B of this part.

§ 60.4005 Definitions

Terms used but not defined in this subpart have the meaning given them in the Act and in subparts A, B, and Da of this part.

§ 60.4010 Designated Facilities

(a) The designated facility to which the emission guidelines apply is each existing electric utility steam generating unit for which construction, reconstruction or modification was commenced before January 30, 2004.

(b) Physical or operational changes made to an existing electric utility steam generating unit solely to comply with an emission guideline are not considered a modification or reconstruction and

would not subject an existing electric utility steam generating unit to the requirements of subpart Da (*see* § 60.40a of subpart Da).

§ 60.4015 Emission Guidelines for Oil-fired Electric Utility Steam Generating Units

For approval, a State plan shall include emission limits for nickel (Ni) at least as protective as the provisions specified in paragraphs (a) and (b) of this section.

(a) The emission limit for Ni contained in the gases discharged to the atmosphere from a designated facility is 210 pounds of Ni per trillion Btu (lb/TBtu) in an input-based format and 0.002 pounds of Ni per megawatt hour (lb/MWh) in an output-based format. The SI equivalent is 0.25 ng/J.

(b) The emission limit for Ni for oil-fired electric utility steam generating units does not apply if the owner/operator permanently uses distillate oil as fuel. Except as provided in paragraph (5) of this section, the emissions limit for Ni for oil-fired electric utility steam generating units will immediately apply if the owner/operator subsequently uses a fuel other than distillate oil.

(c) If you use an electrostatic precipitator (ESP) to meet a Ni emissions limit in this part, you must operate the ESP such that the hourly average voltage and secondary current (or total power input) do not fall below the limit established in the initial or subsequent performance test.

(d) If you use a control device or combination of control devices other than an ESP to meet the Ni emissions limit, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters for an ESP, you must apply to the Administrator for approval of alternative monitoring under § 60.13(i).

(e) If you comply with the requirements in § 60.4015(b) for switching fuel, and you must switch fuel because of an emergency, you must notify the Administrator in writing within 30 days of using a fuel other than distillate oil.

§ 60.4020 Compliance Provisions and Performance Testing

For approval, a State plan shall include the performance testing compliance demonstration requirements as listed in paragraphs (a) and (b) of this section.

(a) Affected facilities will conduct a performance test to demonstrate compliance with this section no later than 180 days after the initial startup or 180 days after publication of the final amendments, whichever is later and annually thereafter. The performance test is to be conducted using Method 29 of appendix A of this part to determine Ni emission concentration in the flue gas stream. The Ni emissions concentration for compliance under this part is determined by the three-run average (nominal 1-hour runs) using Method 29 of appendix A of this part for the initial and subsequent performance tests.

(b) The owner or operator shall demonstrate compliance with the Ni limit in § 60.46a according to the procedures in this paragraph to convert the Method 29 Ni measurement from the performance test to the selected format for comparison to the applicable § 60.46a Ni emission limits.

(1) Sum the Ni concentrations obtained from the Method 29 test runs, milligrams per dscm (mg/dscm).

(2) Calculate the total volumetric flow obtained during the Method 29 test runs, (dscm).

(3) Multiply the total Ni concentration times the total volumetric flow for the duration of the initial compliance testing period to obtain the total mass of Ni in milligrams.

(4) Calculate the input-based Ni emissions rate in a lb/TBtu format using Equation 1 of this section.

$$ER = \frac{M \times \text{conversion factor}}{TP_{\text{input-based}}} \qquad \text{(Eq. 1)}$$

Where:

ER = Ni emissions rate, (lb/TBtu);
M = Total mass of Ni emissions, (mg);
Conversion factor = 2.205×10^{-6}; used to convert milligrams to pounds; and
$TP_{\text{input-based}}$ = Total power, (TBtu).

(5) Calculate the output-based Ni emissions rate in a lb/MWh format using Equation 2 of this section.

$$ER = \frac{M \times \text{conversion factor}}{TP_{\text{output-based}}} \qquad \text{(Eq. 2)}$$

Where:

ER = Ni emissions rate, (lb/MWh);
M = Total mass of Ni emissions, (mg);
Conversion factor = 2.205×10^{-6}; and
$TP_{\text{output-based}}$ = Total power, (MWh).

§ 60.4025 Reporting and Recordkeeping Guidelines

For approval, a State plan shall include the reporting and recordkeeping provisions listed in § 60.52a of subpart Da of this part, as applicable.

§ 60.4030 Compliance Times

(a) Except as provided for under paragraph (b) of this section, planning, awarding of contracts, and installation of electric utility steam generating unit air emission control equipment capable of meeting the emission guidelines established under § 60.4015 shall be accomplished within 30 months after the effective date of a State emission standard for electric utility steam generating units.

APPENDIX B PART 60

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

Performance Specification 12a—Specifications and Test Procedures for Total Vapor Phase Mercury Continuous Emission Monitoring Systems in Stationary Sources

1.0 Scope and Application

1.1 Analyte.

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

1.2 Applicability.

1.2.1 This specification is for evaluating the acceptability of total vapor phase Hg continuous emission monitoring systems (CEMS) installed on the exit gases from fossil fuel fired boilers at the time of or soon after installation and whenever specified in the regulations. The Hg CEMS must be capable of measuring the total concentration in μg/m^3 (regardless of speciation) of vapor phase Hg, and recording that concentration on a dry basis, corrected to 20 degrees C and 7 percent CO_2. Particle bound Hg is not included. The CEMS must include a) a diluent (CO_2) monitor, which must meet Performance Specification 3 in 40 CFR part 60, appendix B, and b) an automatic sampling system. Existing diluent and flow monitoring equipment can be used.

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 CAA section 114, the operator to conduct CEMS performance evaluations at other times besides the initial test to evaluate the CEMS performance. See 40 CFR 60.13(c).

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 CEMS that measures the total vapor phase Hg mass concentration and generates a proportional output.

3.4 *Diluent Analyzer* (if applicable) means that portion of the CEMS that senses the diluent gas (CO_2) and generates an output proportional to the gas concentration.

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

3.6 *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.

3.7 *Measurement Error (ME)* means the difference between the concentration indicated by the CEMS and the known concentration generated by a reference gas when the entire CEMS, including the sampling interface, is challenged. An ME test procedure is performed to document the accuracy and linearity of the CEMS at several points over the measurement range.

3.8 *Upscale Drift (UD)* means the difference in the CEMS output responses to a Hg reference gas 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 *Zero Drift (ZD)* means the difference in the CEMS output responses to a zero gas 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.

3.10 *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 or the applicable emission limit.

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 reference method 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 CEMS data recorder output range must include zero and a high level value. The high level value must be approximately 2 times the Hg concentration corresponding to the emission standard level for the stack gas under the circumstances existing as the stack gas is sampled. If a lower high level value is used, the CEMS must have the capability of providing multiple high level values (one of which is equal to the span value) or be capable of automatically changing the high level value as required (up to specified high level value) such that the measured value does not exceed 95 percent of the high level value.

6.1.2 The CEMS design should also provide for the determination of response drift at both the zero and mid-level value. If this is not possible or practical, the design must allow these determinations to be conducted at a low-level value (zero to 20 percent of the high-level value) and at a 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.

7.1.1 Zero—N_2 or Air. Less than 0.1 μg Hg/m^3.

7.1.2 Mid-level Hg^0 and $HgCl_2$. 40 to 60 percent of span.

7.1.3 High-level Hg^0 and $HgCl_2$. 80 to 100 percent of span.

7.2 Reagents and Standards. May be required for the reference methods. See Section 8.6.2.

8.0 Performance Specification 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 eight equivalent diameters downstream of the nearest control device, point of pollutant generation, bend, or other point at which a change of pollutant concentration or flow disturbance may occur, and (2) at least two equivalent diameters 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 Reference Method (RM) Measurement Location and Traverse Points. The RM measurement location should be at a point or points in the same stack cross sectional area as the CEMS is located, according to the criteria above. The RM and CEMS locations need not be immediately adjacent. They should be as close as possible without causing interference with one another.

8.3 Measurement Error (ME) Test Procedure. The Hg CEMS must be constructed to permit the introduction of known (NIST traceable) concentrations of elemental mercury (Hg^0) and mercuric chloride ($HgCl_2$) separately into the sampling system of the CEMS immediately preceding the sample extraction filtration system such that the entire CEMS can be challenged. Inject sequentially each of the three reference gases (zero, mid-level, and high level) for each Hg species. CEMS measurements of each reference gas shall not differ from their respective reference values by more than 5 percent of the span value. If this specification is not met, identify and correct the problem before proceeding.

8.4 Upscale Drift (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) for 7 consecutive days according to the procedure given in Sections 8.4.2 through 8.4.3.

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 the mid-level point specified in Section 7.1. Evaluate upscale drift for elemental Hg (Hg^0) only. Introduce the reference gas to the CEMS. Record the CEMS response and subtract the reference value from the CEM value (see example data sheet in Figure 12A–1).

8.5 Zero Drift (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) for 7 consecutive days according to the procedure given in Sections 8.5.2 through 8.5.3.

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 CEM value (see example data sheet in Figure 12A–1).

8.6 Relative Accuracy (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 can be conducted during the UD test period.

8.6.2 Reference Method (RM). Unless otherwise specified in an applicable subpart of the regulations, use either Method 29 in appendix A to 40 CFR part 60, or ASTM Method D 6784–02 (incorporated by reference in § 60.17) as the RM for Hg. Do not include the filterable portion of the sample when making comparisons to the CEMS results. Conduct all RM tests with paired or duplicate sampling systems.

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 the diluent (if applicable), moisture (if needed), and Hg measurements simultaneously. However, diluent and moisture measurements that are taken within an hour of the Hg measurements can used to adjust the results to a consistent 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 paired sets of all necessary RM test runs that meet the relative standard deviation criteria of this PS. Use a minimum sample run time of 2 hours for each pair.

Note: More than nine paired sets of RM tests can be performed. If this option is chosen, test results can be rejected 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 rejected 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 or emission rate for each pollutant RM test period. Consider system response time, if important, and confirm that the results are on a consistent moisture, temperature, and diluent concentration basis with the paired RM test. Then, compare each integrated CEMS value against the corresponding average of the paired RM values.

8.6.6 Paired RM Outliers.

8.6.6.1 Outliers are identified through the determination of precision and any systematic bias 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 dual RM sampling is to generate information to quantify the precision of the RM data. The relative standard deviation (RSD) of paired data is the parameter used to quantify data precision. Determine RSD for two simultaneously gathered data points as follows:

$$RSD = 100\% * \left|(Ca - Cb)\right| / (Ca + Cb) \qquad \text{Eq. 12A-1}$$

where Ca and Cb are concentration values determined from trains A and B respectively. For RSD calculation, the concentration units are unimportant so long as they are consistent.

8.6.6.2 A minimum precision criteria for RM Hg data is that RSD for any data pair must be ≤10 percent as long as the mean Hg concentration is greater than 1.0 μg/m^3. If the mean Hg concentration is less than or equal to 1.0 μg/m^3, the RSD must be ≤20 percent. Pairs of RM data exceeding these RSD 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 the emission standard, 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 Performance Specification (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 Performance Specification 2.

12.1 Consistent Basis. All data from the RM and CEMS must be on a consistent dry basis and, as applicable, on a consistent diluent basis. Correct the RM and CEMS data for moisture and diluent as follows:

12.1.1 Moisture Correction (as applicable). Correct each wet RM run for moisture with the corresponding Method 4 data; correct each wet CEMS run using the corresponding CEMS moisture monitor date using Equation 12A–2.

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

12.1.2 Correction to Units of Standard (as applicable). Correct each dry RM run to the units of the emission standard with the corresponding Method 3B data; correct each dry CEMS run using the corresponding CEMS diluent monitor data as follows:

12.1.3 Correct to Diluent Basis. The following is an example of concentration (ppm) correction to 7 percent oxygen.

$$ppm_{(corr)} = ppm_{(uncorr)}\left[\frac{20.9 - 7.0}{20.9 - \%O_{2\,(dry)}}\right] \qquad \text{Eq. 12A-3}$$

The following is an example of mass/gross calorific value (lbs/million Btu) correction. lbs/MMBtu = $Conc_{(dry)}$ (F-factor) ((20.9/(20.9—percent O_2))

12.2 Arithmetic Mean. Calculate the arithmetic mean of the difference, d, of a data set as follows:

$$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i \qquad \text{Eq. 12A-4}$$

Where:

n = Number of data points.

12.3 Standard Deviation. Calculate the standard deviation, S_d, as follows:

$$S_d = \left[\frac{\sum_{i=1}^{n} d_i^2 - \frac{\left[\sum_{i=1}^{n} d_i\right]^2}{n}}{n-1}\right]^{\frac{1}{2}} \qquad \text{Eq. 12A-5}$$

Where:

$\sum_{i=1}^{n} d_i$ = Algebraic summation of the individual differences d_i.

12.4 Confidence Coefficient. Calculate the 2.5 percent error confidence coefficient (one-tailed), CC, as follows:

$$CC = t_{0.975}\frac{S_d}{\sqrt{n}} \qquad \text{Eq. 12A-6}$$

12.5 Relative Accuracy. Calculate the RA of a set of data as follows:

Where:

$|\bar{d}|$ = Absolute value of the mean differences (from Equation 12A–4).

|CC| = Absolute value of the confidence coefficient (from Equation 12A–6).

$R\overline{M}$ = Average RM value. In cases where the average emissions for the test are less than 50 percent of the applicable standard, substitute the emission standard value in the denominator of Eq. 12A–7 in place of $R|\overline{M}|$. In all other cases, use R|M|

13.0 Method Performance

13.1 Measurement Error (ME). ME is assessed at 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 span. The same difference for the zero reference gas

$$RA = \frac{\left[|\bar{d}| + |CC|\right]}{R\overline{M}} \times 100 \qquad \text{Eq. 12A-7}$$

shall be no greater than 5 percent of span.

13.2 Upscale Drift (UD). The CEMS design must allow the determination of UD of the analyzer. The CEMS response can not drift or deviate from the benchmark value of the reference standard by more than 5 percent of span for the mid level value. Evaluate upscale drift for Hg^0 only.

13.3 Zero Drift (ZD). The CEMS design must allow the determination of drift at the zero level. This drift shall not exceed 5 percent of span.

13.4 Relative Accuracy (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 the emission standard, or 10 percent of the applicable standard, whichever is greater.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 Alternative Procedures. [Reserved]

17.0 Bibliography.

17.1 40 CFR part 60, appendix B, ''Performance Specification 2—Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources.''

17.2 40 CFR part 60, appendix A, ''Method 29—Determination of Metals Emissions from Stationary Sources.''

17.3 ASTM Method D6784–02, ''Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method).''

18.0 *Tables and Figures.*

TABLE 12A–1.—T-VALUES.

n [a]	$t_{0.975}$	n [a]	$t_{0.975}$	n [a]	$t_{0.975}$
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	15	2.145
6	2.571	11	2.228	16	2.131

[a] The values in this table are already corrected for n-1 degrees of freedom. Use n equal to the number of individual values.

	Day	Date and time	Reference value (C)	CEMS value (M)	Measurement error	Drift
Zero Level						
Mid-level						

	Day	Date and time	Reference value (C)	CEMS value (M)	Measurement error	Drift
High-level						

Figure 12A–1.—Zero and Upscale Drift Determination

PART 63—[AMENDED]

11. The authority citation for part 63 continues to read as follows:

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

12. Section 63.14 is amended by adding paragraph (b)(35) to read as follows:

§ 63.14 Incorporations by Reference.

* * * * *

(b) * * *

(35) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), for appendix B to part 63, Method 324.

* * * * *

APPENDIX B PART 63

13. Appendix B to part 63 is amended by adding in numerical order new Method 324 to read as follows:

Method 324—Determination of Vapor Phase Flue Gas Mercury Emissions From Stationary Sources Using Dry Sorbent Trap Sampling

1.0 Introduction.

This method describes sampling criteria and procedures for the continuous sampling of mercury (Hg) emissions in combustion flue gas streams using sorbent traps. Analysis of each trap can be by cold vapor atomic fluorescence spectrometry (AF) which is described in this method, or by cold vapor atomic absorption spectrometry (AA). Only the AF analytical method is detailed in this method, with reference being made to other published methods for the AA analytical procedure. The Electric Power Research Institute has investigated the AF analytical procedure in the field with the support of ADA–ES and Frontier Geosciences, Inc. The AF procedure is based on EPA Method 1631, Revision E: Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Fluorescence Spectrometry. Persons using this method should have a thorough working knowledge of Methods 1, 2, 3, 4 and 5 of 40 CFR part 60, appendix A.

1.1 Scope and Application.

1.1.1 Analytes. The analyte measured by this method is total vapor-phase Hg, which represents the sum of elemental (CAS Number 7439–97–6) and oxidized forms of Hg, mass concentration (micrograms/dscm) in flue gas samples.

1.1.2 Applicability. This method is applicable to the determination of vapor-phase Hg concentrations ranging from 0.03 µg/dncm to 100 µg/dncm in low-dust applications, including controlled and uncontrolled emissions from stationary sources, only when specified within the regulations. When employed to demonstrate compliance with an emission regulation, paired sampling is to be performed as part of the method quality control procedure. The method is appropriate for flue gas Hg measurements from combustion sources. Very low Hg concentrations will require greater sample volumes. The method can be used over any period from 30 minutes to several days in duration, provided appropriate sample volumes are collected and all the quality control criteria in Section 9.0 are met. When sampling for periods greater than 12 hours, the sample rate is required to be maintained at a constant proportion to the total stack flowrate, ±25 percent to ensure representativeness of the sample collected.

2.0 Summary of Method.

Known volumes of flue gas are extracted from a duct through a single or paired sorbent trap with a nominal flow rate of 0.2 to 0.6 liters per minute through each trap. Each trap is then acid leached and the resulting leachate is analyzed by cold vapor atomic fluorescence spectrometry (CVAFS) detection. The AF analytical procedure is described in detail in EPA Method 1631. Analysis by AA can be performed by existing recognized procedures, such as that contained in ASTM Method D6784–02 (incorporated by reference, see § 63.14) or EPA Method 29.

3.0 Definitions. [Reserved]

4.0 Clean Handling and Contamination.

During preparation of the sorbent traps, as well as transport, field handling, sampling, recovery, and laboratory analysis, special attention must be paid to cleanliness procedures. This is to avoid Hg contamination of the samples, which generally contain very small amounts of Hg. For specifics on how to avoid contamination, Section 4 of Method 1631 should be well understood.

5.0 Safety.

5.1 Site hazards must be prepared for in advance of applying this method in the field. Suitable clothing to protect against site hazards is required, and requires advance coordination with the site to understand the conditions and applicable safety policies. At a minimum, portions of the sampling system will be hot, requiring appropriate gloves, long sleeves, and caution in handling this equipment.

5.2 Laboratory safety policies are to minimize risk of chemical exposure and to properly handle waste disposal. Personnel will don appropriate laboratory attire according to a Chemical Hygiene Plan established by the laboratory. This includes, but is not limited to, laboratory coat, safety goggles, and nitrile gloves under clean gloves.

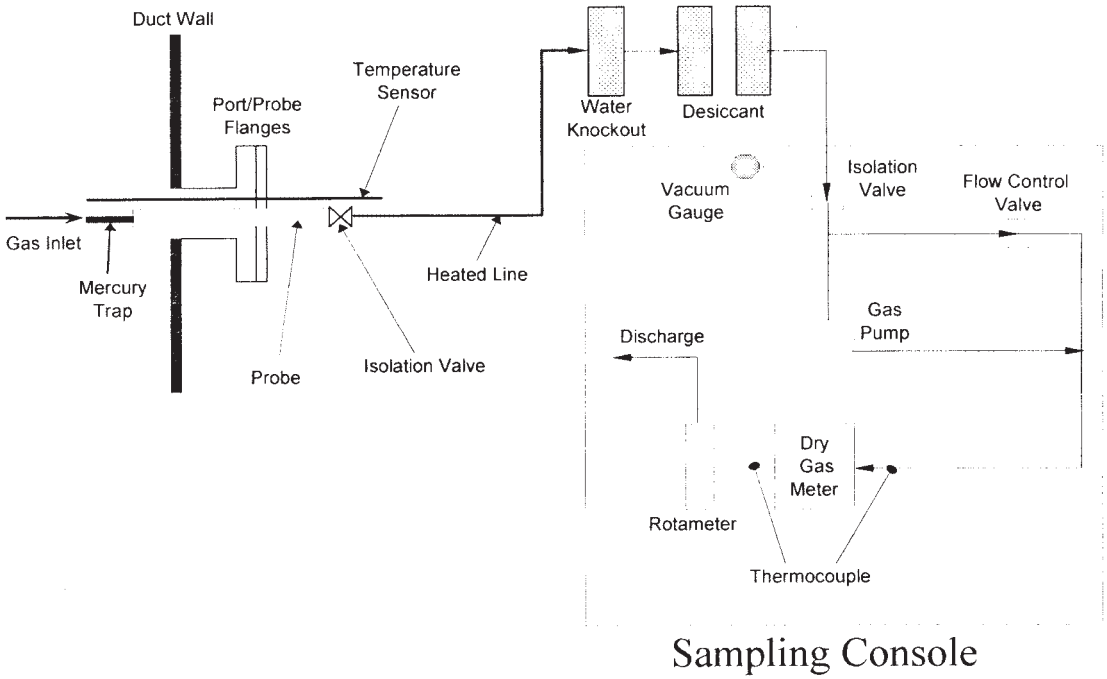
5.3 The toxicity or carcinogenicity of reagents used in this method has not been fully established. The procedures required in this method may involve hazardous materials, operations, and equipment. This method may not address all of the safety problems associated with these procedures. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performing these procedures. Each chemical should be regarded as a potential health hazard and exposure to these compounds should be minimized. Chemists should refer to the MSDS for each chemical with which they are working.

5.4 Any wastes generated by this procedure must be disposed of according to a hazardous materials management plan that details and tracks various waste streams and disposal procedures.

6.0 Equipment and Supplies.

6.1 Hg Sampling Train. A Schematic of a single trap sampling train used for this method is shown in Figure 324–1. Where this method is used to collect data to demonstrate compliance with a regulation, it must be performed with paired sorbent trap equipment.

Figure 324–1. Hg Sampling Train illustrating Single Trap.



6.1.1 Sorbent Trap. Use sorbent traps with separate main and backup sections in series for collection of Hg. Selection of the sorbent trap shall be based on: (1) Achievement of the performance criteria of this method, and (2) data is available to demonstrate the method can pass the criteria in EPA Method 301 when used in this method and when the results are compared with those from EPA Method 29, EPA Method 101A, or ASTM Method 6784–02 for the measurement of vapor-phase Hg in a similar flue gas matrix. Appropriate traps are referred to as ''sorbent trap'' throughout this method. The method requires the analysis of Hg in both main and backup portions of the sorbent within each trap. The sorbent trap should be obtained from a reliable source that has clean handling procedures in place for ultra low-level Hg analysis. This will help assure the low Hg environment required to manufacture sorbent traps with low blank levels of Hg. Sorbent trap sampling requirements or needed characteristics are shown in Table 324–1. Blank/cleanliness and other requirements are described in Table 324–2. The sorbent trap is supported on a probe and inserted directly into the flue gas stream, as shown on Figure 324–1. The sampled sorbent trap is the entire Hg sample.

6.1.2 Sampling Probe. The probe assembly shall have a leak-free attachment to the sorbent trap. For duct temperatures from 200 to 375°F, no heating is required. For duct temperatures less than 200°F, the sorbent tube must be heated to at least 200°F or higher to avoid liquid condensation in the sorbent trap by using a heated probe. For duct temperatures greater than 375°F, a large sorbent trap must be used, as shown in Table 324–1, and no heating is required. A thermocouple is used to monitor stack temperature.

6.1.3 Umbilical Vacuum Line. A 250 °F heated umbilical line shall be used to convey to the moisture knockout the sampled gas that has passed through the sorbent trap and probe assembly.

6.1.4 Moisture Knockout. Impingers and desiccant can be combined to dry the sample gas prior to entering the dry gas meter. Alternative sample drying methods are acceptable as long as they do not affect sample volume measurement.

6.1.5 Vacuum Pump. A leak tight vacuum pump capable of delivering a controlled extraction flow rate between 0.1 to 0.8 liters per minute.

6.1.6 Dry Gas Meter. Use a dry gas meter that is calibrated according to the procedures in 40 CFR part 60, appendix A, Method 5, to measure the total sample volume collected. The dry gas meter must be sufficiently accurate to measure the sample volume within 2 percent, calibrated at the selected flow rate and conditions actually encountered during sampling, and equipped with a temperature sensor capable of measuring typical meter temperatures accurately to within 3 °C (5.4 °F).

6.2 Sample Analysis Equipment. Laboratory equipment as described in Method 1631, Sections 6.3 to 6.7 is required for analysis by AF. For analysis by AA, refer to Method 29 or ASTM Method 6784–02.

TABLE 324–1.—SORBENT TRAP AND SAMPLING REQUIREMENTS

Item to be determined	Small sorbent trap	Large sorbent trap
Sampling Target: Hg Loading Range, ug	Minimum = 0.025 µg/trap.	Minimum = 0.10 µg/trap.
	Maximum = 150 µg/trap	Maximum = 1800 µg/trap.
Sampling Duration Required: limits on sample times.	Minimum = 30 minutes	Minimum = 24 hours.
	Maximum = 24 hours	Maximum = 10 days.
Sampling Temperature Required	200 to 375 °F	200 to 425 °F.
Sampling Rate Required	0.2 to 0.6 L/min; start at 0.4 L/min	0.2 to 0.6 L/min; start at 0.4 L/min.
	Must be constant proportion within ±25% if greater than 12 hours; constant rate within ±25% if less than 12 hours.	Must be constant proportion of stack flowrate within ±25%.

7.0 Analysis by AF, Reagents and Standards.

For analysis by AF, use Method 1631, Sections 7.1–7.3 and 7.5–7.12 for laboratory reagents and standards. Refer to Method 29 or ASTM Method 6784–02 for analysis by AA.

7.1 Reagent Water. Same as Method 1631, Section 7.1.

7.2 Air. Same as Method 1631, Section 7.2.

7.3 Hydrochloric Acid. Same as Method 1631, Section 7.3.

7.4 Stannous Chloride. Same as Method 1631, Section 7.5.

7.5 Bromine Monochloride (BrCl, 0.01N). Same as Method 1631, Section 7.6.

7.6 Hg Standards. Same as Method 1631, Sections 7.7 to 7.11.

7.7 Nitric Acid. Reagent grade, low Hg.

7.8 Sulfuric Acid. Reagent grade, low Hg.

7.9 Nitrogen. Same as Method 1631, Section 7.12.

7.10 Argon. Same as Method 1631, Section 7.13.

8.0 Sample Collection and Transport.

8.1 Pre-Test.

8.1.1 Site information should be obtained in accordance with Method 1 (40 CFR part 60, appendix A). Identify a location that has been shown to be free of stratification for SO_2 and NO_X through concentration measurement traverses for those gases. An estimation of the expected Hg concentration is required to establish minimum sample volumes. Based on estimated minimum sample volume and normal sample rates for each size trap used, determine sampling duration with the data provided in Table 324–1.

8.1.2 Sorbent traps must be obtained from a reliable source such that high quality control and trace cleanliness are maintained. Method detection limits will be adversely affected if adequate cleanliness is not maintained. Sorbent traps should be handled only with powder-free low Hg gloves (vinyl, latex, or nitrile are acceptable) that have not touched any other surface. The sorbent traps should not be removed from their clean storage containers until after the preliminary leak check has been completed. Field efforts at clean handling of the sorbent traps are key to the success of this method.

8.1.3 Assemble the sample train according to Figure 324–1, except omit the sorbent trap.

8.1.4 Preliminary Leak Check. Perform system leak check without the single or dual sorbent traps in place. This entails plugging the end of the probe to which each sorbent trap will be affixed, and using the vacuum pump to draw a vacuum in each sample train. Adjust the vacuum in the sample train to 15 inches Hg. A rotameter on the dry gas meter will indicate the leakage rate. The leakage rate must be less than 2 percent of the planned sampling rate.

8.1.5 Release the vacuum in the sample train, turn off the pump, and affix the sorbent trap to the end of the probe, using clean handling procedures. Leave the flue gas end of the sorbent trap plugged.

8.1.6 Pre-test leak check. Perform a leak check with the Sorbent trap in place. Use the sampling vacuum pump to draw a vacuum in the sample train. Adjust the vacuum in the sample train to 15 inches Hg. A rotameter on the dry gas meter will indicate the leakage rate. Record the leakage rate. The leakage rate must be less than 2 percent of the planned sampling rate. Once the leak check passes this criterion, carefully release the vacuum in the sample train (the sorbent trap must not be exposed to abrupt changes in pressure or to backflow), then re-cap the flue gas end of the sorbent trap until the probe is ready for insertion. The sorbent trap packing beds must be undisturbed by the leak test to prevent gas channeling through the media during sampling.

8.1.7 Use temperature controllers to heat the portions of the trains that require it. The sorbent trap must be maintained between 200 and 375 °F during sampling.

8.1.8 Gas temperature and static pressure must be considered prior to sampling in order to maintain proper safety precautions during sampling.

8.2 Sample Collection.

8.2.1 Remove the plug from the end of a sorbent trap and store it in a clean sorbent trap storage container. Remove the sample duct port cap and insert the probe. Secure the probe and ensure that no leakage occurs between the duct and environment.

8.2.2 Record initial data including the start time, starting dry gas meter readings, and the name of the field tester(s). Set the initial sample flow rate to 0.4 L/min (+/−25 percent).

8.2.3 For constant-flow sampling (samples less than 12 hours in duration), every 10–15 minutes during the sampling period: record the time, the sample flow rate, the gas meter readings, the duct temperature, the flow meter temperatures, temperatures of heated equipment such as the vacuum lines and the probes (if heated), and the sampling vacuum reading. Adjust the sample rate as needed, maintaining constant sampling within +/−25 percent of the initial reading.

8.2.4 For constant proportion sampling (samples 12 hours or greater in duration), every hour during the sampling period: record the time, the sample flow rate, the gas meter readings, the duct temperature, the flow meter temperatures, temperatures of heated equipment such as the vacuum lines and the probes (if heated), and the sampling vacuum readings. Also record the stack flow rate reading, whether provided as a CEM flow monitor signal, a pitot probe or other direct flow indication, or a plant input signal. Adjust the sampling rate to maintain proportional sampling within +/−25 percent relative to the total stack flowrate.

8.2.5 Obtain and record operating data for the facility during the test period, including total stack flowrate and the oxygen concentration at the flue gas test location. Barometric pressure must be obtained for correcting sample volume to standard conditions.

8.2.6 Post Test Leak Check. When sampling is completed, turn off the sample pump, remove the probe from the port and carefully re-plug the end of the sorbent trap. Perform leak check by turning on the sampling vacuum pumps with the plug in place. The rotameter on the dry gas meters will indicate the leakage rates. Record the leakage rate and vacuum. The leakage rate must be less than 2 percent of the actual sampling rate. Following the leak check, carefully release the vacuum in the sample train.

8.2.7 Sample Recovery. Recover each sampled sorbent trap by removing it from the probe, plugging both ends with the clean caps provided with the sorbent trap, and then wiping any dirt off the outside of the sorbent trap. Place the sorbent trap into the clean sample storage container in which it was provided, along with the data sheet that includes the post-test leak check, final volume, and test end time.

8.3 Quality Control Samples and Requirements.

8.3.1 Field blanks. Refer to Table 324–2.

8.3.2 Duplicate (paired or side by side) samples. Refer to Section 8.6.6 of Performance Specification 12A of 40 CFR part 60, appendix B for this criteria.

8.3.3 Breakthrough performance data (''B'' bed in each trap, or second traps behind). Refer to Table 324–2.

8.3.4 Field spikes (sorbent traps spiked with Hg in the lab and periodically sampled in the field to determine overall accuracy). Refer to Table 324–2.

8.3.5 Laboratory matrix and matrix spike duplicates. Refer to Table 324–2.

9.0 Quality Control.

Table 324–2 summarizes the major quantifiable QC components.

TABLE 324–2.—QUALITY CONTROL FOR SAMPLES

QA/QC specification	Acceptance criteria	Frequency	Corrective action
Leak-check.	<2% of sampling rate.	Pre- and post-sampling.	Pre-sampling: repair leak. Post sampling: Flag data and repeat run if for regulatory compliance.
Sample Flow Rate for samples less than 12 hours in duration.	0.4 L/min initially and ±25% of initial rate throughout run.	Throughout run every 10–15 minutes.	Adjust when data is recorded.
Sample Flow Rate for samples greater than 12 hours in duration.	0.4 L/min initially and maintain ±25% of ration of flue gas flow rate throughout sampling.	Throughout run every hour.	Adjust when data is recorded.

TABLE 324–2.—QUALITY CONTROL FOR SAMPLES—Continued

QA/QC specification	Acceptance criteria	Frequency	Corrective action
Sorbent trap laboratory blank (same lot as samples).	<5 ng/trap and a standard deviation of <1:0 ng/trap (n=3).	3 per analysis set of 20 sorbent traps.	
Sorbet trap field blank (same lot as samples)	<5 ng/trap and a standard deviation of <1.0 ng/trap (n=3) OR <5% of average sample collected.	1 per every 10 field samples collected.	
B-Trap Bed Analysis.	<2% of A-Trap Bed Value OR < 5 ng/trap.	Every sample.	
Paired Train Results.	Same as Section 8.6.6 of PS–12A of 40 CFR Par 60, Appendix B.		
Field Spikes.	80% to 120% recovery.	For long-term regulatory monitoring, 1 per every 3 samples for the first 12 samples.	If the first 4 field spikes do not meet the ±20% criteria, take corrective sampling and laboratory measures and repeat at the 1 per every 3 sample rate until the ±20% criteria is met.
Laboratory matrix and matrix spike duplicates.	85% to 115% recovery.	1 per every 10 or 20 samples—to be determined.	

10.0 Calibration and Standards.

Same as Sections 10.1, 10.2 and 10.4 of Method 1631.

10.1 Calibration and Standardization. Same as Sections 10.1 and 10.4 of Method 1631.

10.2 Bubbler System. Same as Section 10.2 of M1631.

10.3 Flow-Injection System. Not applicable.

11.0 Analytical Procedures.

11.1 Preparation Step. The sorbent traps are received and processed in a low-Hg environment (class-100 laminar-flow hood and gaseous Hg air concentrations below 20 ng/m^3) following clean-handling procedures. Any dirt or particulate present on the exterior of the trap must be removed to avoid contamination of the sample. The sorbent traps are then opened and the sorbent bed(s) transferred to an appropriate sized trace-clean vessel. It is recommended that the height of the trace-clean vessel be at least 3 times the diameter to facilitate a refluxing action.

11.2 Leaching Step. The sorbent trap is then subjected to a hot-acid leach using a 70:30 ratio mixture of concentrated HNO_3/H_2SO_4. The acid volume must be 40 percent of the expected end volume of the digest after dilution. The HNO_3/H_2SO_4 acid to carbon ratio should be approximately 35:1. The leachate is then heated to a temperature of 50 to 60°C for 1.5 to 2.0 hours in the finger-tight capped vessels. This process may generate significant quantities of noxious and corrosive gasses and must only be performed in a well-ventilated fume hood. Care must be taken to prevent excessive heated leaching of the samples as this will begin to break down the charcoal material.

11.3 Dilution Step. After the leached samples have been removed from the hot plate and allowed to cool to room temperature, they are brought to volume with a 5 percent (v/v) solution of 0.01 N BrCl. As the leaching digest contains a substantial amount of dissolved gasses, add the BrCl slowly, especially if the samples are still warm. As before, this procedure must be performed in a properly functioning fume hood. The sample is now ready for analysis.

11.4 Hg Reduction and Purging. (Reference Section 11.2 of M1631 except that NH_2OH is not used.)

11.4.1 Bubbler System. Pipette an aliquot of the digested sample into the bubbler containing pre-blanked reagent water and a soda lime trap connected to the exhaust port. Add stannous chloride ($SnCl_2$) to reduce the aliquot and then seal the bubbler. Connect gold sample traps to the end of the soda lime trap as shown in Figures 1 and 2 of Method 1631. Finally, connect the N_2 lines and purge for 20 minutes. The sample trap can then be added into the analytical train. M1631, Section 11.2.1.

11.4.2 Flow Injection System. If required.

11.5 Desorption of Hg from the gold trap, and peak evaluation. Use Section 11.3 and 11.4 in M1631.

11.6 Instrument Calibration. Analyze the standards by AA or AF following the guidelines specified by the instrument manufacturer. Construct a calibration curve by plotting the absorbances of the standards versus µg/l Hg. The R^2 for the calibration curve should be 0.999 or better. If the curve does not have an R^2 value equal to or better than 0.999 then the curve should be rerun. If the curve still does not meet this criteria then new standards should be prepared and the instrument recalibrated. All calibration points contained in the curve must be within 10 percent of the calibration value when the calibration curve is applied to the calibration standards.

11.7 Sample Analysis. Analyze the samples in duplicate following the same procedures used for instrument calibration. From the calibration curve, determine sample Hg concentrations. To determine total Hg mass in each sample fraction, refer to calculations in Section 15. Record all sample dilutions

11.8 Continued Calibration Performance. To verify continued calibration performance, a continuing calibration check standard should be run every 10 samples. The measured Hg concentration of the continuing calibration check standard must be within 10 percent of the expected value.

11.9 Measurement Precision. The QA/QC for the analytical portion of this method is that every sample, after it has been prepared, is to be analyzed in duplicate with every tenth sample analyzed in triplicate. These results must be within 10 percent of each other. If this is not the case, then the instrument must be recalibrated and the samples reanalyzed.

11.10 Measurement Accuracy. Following calibration, an independently prepared standard (not from same calibration stock solution) should be analyzed. In addition, after every ten samples, a known spike sample (standard addition) must be analyzed. The measured Hg content of the spiked samples must be within 10 percent of the expected value.

11.11 Independent QA/QC Checks. It is suggested that the QA/QC procedures developed for a test program include submitting, on occasion, spiked Hg samples to the analytical laboratory by either the prime contractor, if different from the laboratory, or an independent organization. The measured Hg content of reference samples must be within 15 percent of the expected value. If this limit is exceeded, corrective action (*e.g.,* re-calibration) must be taken and the samples re-analyzed.

11.12 Quality Assurance/Quality Control. For this method, it is important that both the sampling team and analytical people be very well trained in the procedures. This is a complicated method that requires a high-level of sampling and analytical experience. For the sampling portion of the QA/QC procedure, both solution and field blanks are required. It should be noted that if high-quality reagents are used and care is taken in their preparation and in the train assembly, there should be little, if any, Hg measured in either the solution or field blanks.

11.13 Solution Blanks. Solution blanks must be taken and analyzed every time a new batch of solution is prepared. If Hg is detected in these solution blanks, the concentration is subtracted from the measured sample results. The maximum amount that can be subtracted is 10 percent of the measured result or 10 times the detection limit of the instrument whichever is lower. If the solution blanks are greater

than 10 percent the data must be flagged as suspect.

11.14 Field Blanks. A field blank is performed by assembling a sample train, transporting it to the sampling location during the sampling period, and recovering it as a regular sample. These data are used to ensure that there is no contamination as a result of the sampling activities. A minimum of one field blank at each sampling location must be completed for each test site. Any Hg detected in the field blanks cannot be subtracted from the results. Whether or not the Hg detected in the field blanks is significant is determined based on the QA/QC procedures established prior to the testing. At a minimum, if field blanks exceed 30 percent of the measured value at the corresponding location, the data must be flagged as suspect.

12.0 Calculations and Data Analysis

Use Section 12 in M1631.

13.0 Constant Proportion Sampling

Calculate the Sample Rate/Stack Flow = ''x.'' ''X'' must be maintained within 0.75 ''x'' to 1.25 ''x'' for sampling times in excess of 12 hours. For mass emission rate calculations, use the flow CEM total measured flow corresponding to the sorbent trap sample time period.

14.0 Sampling and Data Summary Calculations

Refer to 40 CFR part 60, appendix A, Methods 2, 4, and 5 for example calculations.

15.0 Pollution Prevention

Refer to Section 13 in Method 1631.

16.0 Waste Management

Refer to Section 14 in Method 1631.

17.0 Bibliography

17.1 EPA Method 1631, Revision E ''Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Fluorescence Spectrometry,'' August 2002.

17.2 ''Comparison of Sampling Methods to Determine Total and Speciated Mercury in Flue Gas,'' CRADA F00–038 Final Report, DOE/NETL–2001/1147, January 4, 2001.

17.3 40 CFR part 60, appendix A, ''Method 29—Determination of Metals Emissions From Stationary Sources.''

17.4 40 CFR part 60, appendix B, ''Performance Specification 12A, Specification and Test Procedures for Total Vapor Phase Mercury Continuous Emission Monitoring Systems in Stationary Sources.''

17.5 ASTM Method D6784–02, ''Standard Test Method for Elemental, Oxidized, Particle-bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method).''

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