ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234; EPA–HQ–OAR–2011–0044, FRL–9286–1]

RIN 2060–AP52

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The United States (U.S.) Environmental Protection Agency (EPA or Agency) is proposing national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units (EGUs) under Clean Air Act (CAA or the Act) section 112(d) and proposing revised new source performance standards (NSPS) for fossil fuel-fired EGUs under CAA section 111(b). The proposed NESHAP would protect air quality and promote public health by reducing emissions of the hazardous air pollutants (HAP) listed in CAA section 112(b). In addition, these proposed amendments to the NSPS are in response to a voluntary remand of a final rule. We also are proposing several minor amendments, technical clarifications, and corrections to existing NSPS provisions for fossil fuel-fired EGUs and large and small industrial-commercial-institutional steam generating units.

DATES: Comments must be received on or before July 5, 2011. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of having full effect if the Office of Management and Budget (OMB) receives a copy of your comments on or before June 2, 2011.

Public Hearing: EPA will hold three public hearings on this proposal. The dates, times, and locations of the public hearings will be announced separately. Oral testimony will be limited to 5 minutes per commenter. The EPA encourages commenters to provide written versions of their oral testimonies either electronically or in paper copy. Verbatim transcripts and written statements will be included in the rulemaking docket. If you would like to present oral testimony at one of the hearings, please notify Ms. Pamela Garrett, Sectors Policies and Programs Division (C504–03), U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541–7966; e-mail: *garrett.pamela@epa.gov.* Persons wishing to provide testimony should notify Ms. Garrett at least 2 days in advance of each scheduled public hearing. For updates and additional information on the public hearings, please check EPA's Web site for this rulemaking, *http://www.epa.gov/ttn/atw/utility/utilitypg.html.* The public hearings will provide interested parties the opportunity to present data, views, or arguments concerning the proposed rule. EPA officials may ask clarifying questions during the oral presentations, but will not respond to the presentations or comments at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearings.

ADDRESSES: Submit your comments, identified by Docket ID. No. EPA–HQ–OAR–2011–0044 (NSPS action) or Docket ID No. EPA–HQ–OAR–2009–0234 (NESHAP action), by one of the following methods:

- *http://www.regulations.gov.* Follow the instructions for submitting comments.
- *http://www.epa.gov/oar/docket.html.* Follow the instructions for submitting comments on the EPA Air and Radiation Docket Web site.
- *E-mail:* Comments may be sent by electronic mail (e-mail) to *a-and-r-docket@epa.gov,* Attention EPA–HQ–OAR–2011–0044 (NSPS action) or EPA–HQ–OAR–2009–0234 (NESHAP action).
- *Fax:* Fax your comments to: (202) 566–9744, Docket ID No. EPA–HQ–OAR–2011–0044 (NSPS action) or Docket ID No. EPA–HQ–OAR–2009–0234 (NESHAP action).
- *Mail:* Send your comments on the NESHAP action to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Docket ID No. EPA–HQ–OAR–2009–0234. Send your comments on the NSPS action to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Docket ID. EPA–HQ–OAR–2011–0044. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, OMB, Attn: Desk Officer for EPA, 725 17th St., NW., Washington, DC 20503.
- *Hand Delivery or Courier:* Deliver your comments to: EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holiday), and special arrangements should be made for deliveries of boxed information.

Instructions: All submissions must include agency name and respective docket number or Regulatory Information Number (RIN) for this rulemaking. All comments will be posted without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available (*e.g.,* CBI or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, 1301 Constitution Avenue, NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For the NESHAP action: Mr. William Maxwell, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–5430; Fax number (919) 541–5450; E-mail address: *maxwell.bill@epa.gov.* For the NSPS action: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–4003; Fax number (919) 541–5450; E-mail address: *fellner.christian@epa.gov.*

SUPPLEMENTARY INFORMATION: The information presented in this preamble is organized as follows:

I. General Information

A. Executive Summary

In December 2000, EPA appropriately concluded that it was appropriate and necessary to regulate hazardous air pollutants (HAP) from EGUs. Today, EPA confirms that finding and concludes that it remains appropriate and necessary to regulate these emissions from EGUs. Hazardous air pollutants from EGUs contribute to adverse health and environmental effects. EGUs are by far the largest U.S. anthropogenic sources of mercury (Hg) emissions into the air and emit a number of other HAP. Both the finding in 2000 and our conclusion that it remains appropriate and necessary to regulate HAP from EGUs are supported by the CAA and scientific and technical analyses.

Mercury is a highly toxic pollutant that occurs naturally in the environment and is released into the atmosphere in significant quantities as the result of the burning of fossil fuels. Mercury in the environment is transformed into a more toxic form, methylmercury (MeHg), and because it is also a persistent pollutant, it accumulates in the food chain, especially the tissue of fish. When people consume these fish they consume MeHg, the consumption of which may cause neurotoxic effects. Children, and, in particular, developing fetuses, are especially susceptible to MeHg effects because their developing bodies are more highly sensitive to its effects. In the December 2000 Finding, we estimated that about 7 percent of women of child-bearing age are exposed to MeHg at a level capable of causing adverse effects in the developing fetus, and that about 1 percent were exposed to 3 to 4 times that level. 65 FR 79827. Moreover, in the 1997 Mercury Study Report to Congress (the "Mercury Study"),[1] we concluded that exposures among specific subpopulations including anglers, Asian-Americans, and members of some Native American Tribes may be more than two-times greater than those experienced by the average U.S. population (U.S. EPA 1997 Mercury Study Report to Congress, Volume IV, page 7–2).

In addition to Hg, EGUs are significant emitters of HAP metals such as arsenic (As), nickel (Ni), cadmium (Cd), and chromium (Cr), which can cause cancer; HAP metals with potentially serious noncancer health effect such as lead (Pb) and selenium (Se); and other toxic air pollutants such as the acid gases hydrogen chloride (HCl) and hydrogen fluoride (HF). Adverse noncancer health effects associated with non-Hg EGU HAP include chronic health disorders (*e.g.,* irritation of the lung, skin, and mucus membranes, effects on the central nervous system, and damage to the kidneys), and acute health disorders (*e.g.,* lung irritation and congestion, alimentary effects such as nausea and vomiting, and effects on the kidney and central nervous system). Three of the key metal HAP emitted by EGUs (As, Cr, and Ni) have been classified as human carcinogens, while another (Cd) is classified as a probable human carcinogen. Current national emissions inventories indicate that EGUs are responsible for 62 percent of the national total emissions of As, 22 percent of the national total emissions of Cr, and 28 percent of the national total emissions of Ni to the atmosphere. Notably, EGUs are also responsible for 83 percent of the national total emissions of Se to the atmosphere.

Congress recognized the threats posed by emissions of HAP and was dissatisfied with the pace of EPA's progress in reducing them prior to 1990. As a result, it enacted significant changes to the CAA that required EPA to develop stringent standards for the control of these pollutants from both stationary and mobile sources. Congress included the requirements in the 1990 CAA amendments regarding acid rain that would reduce emissions of certain criteria pollutants from EGUs and result in the installation of controls that might achieve HAP emission reduction co-benefits. For that reason, it added the requirement for EPA to make a finding before it could regulate EGUs under section 112. Specifically, Congress required in the air toxics provisions that EPA conduct a study of the public health hazards anticipated to remain from EGU HAP emissions after imposition of these other provisions and regulate EGUs under section 112 if the Agency found, after considering the results of the study, that such regulation was appropriate and necessary. Congress also required EPA to conduct a study of Hg emissions from EGUs and other sources and consider the health and environmental effects of the emissions and the availability and cost of control technologies.

Responding to Congress, EPA published the required studies detailing the hazards posed by emissions of Hg and the risks posed by emissions of Hg and other HAP from fossil fuel-fired EGUs. Following the publication of the studies and after collecting additional relevant data, EPA concluded in December 2000 that the threats to public health and the environment from emissions of Hg and other HAP from EGUs made it both appropriate and necessary to adopt regulations under section 112 to reduce the emissions of Hg and other HAP from coal- and oil-fired EGUs. As a result of its findings, EPA added these sources to the list of stationary sources subject to regulations governing the emissions of HAP. However, in a rulemaking effort completed in 2005, EPA reversed its findings and instead adopted regulations under other provisions of the CAA. The DC Circuit Court vacated the resulting regulations, noting that EPA had sidestepped important legal requirements in the CAA that govern the delisting of source categories. Those requirements provide that EPA can delist a source category only if it can demonstrate that no source within the listed category poses a lifetime cancer risk above one in one million to the individual most exposed and that emissions from no source in the category exceed the level that is adequate to protect public health with an ample margin of safety and that no adverse environmental effects will result from the emissions of any source. CAA 112(c)(9)(B). The DC Circuit Court's action restored EPA's December 2000 determination that it was appropriate and necessary to regulate coal- and oil-fired EGUs under section 112, and EGUs remain a listed source category.

EPA reasonably concluded in December 2000, based on the information available to the Agency at that time, that it was appropriate and necessary to regulate EGUs under section 112. Now, more than 10 years have passed since EPA's determination that toxic emissions from coal- and oil-fired EGUs pose a threat to public health and the environment. Although not required, EPA conducted additional, extensive technical analyses based on more recent data, and those analyses confirm that it remains appropriate and necessary to regulate HAPs from coal- and oil-fired EGUs. Accordingly and without further delay, we are proposing a set of HAP emission standards for coal- and oil-fired EGUs that can be met with existing technology that has been available for a significant time.

EPA acknowledges that although EGUs contribute significantly to the total amount of U.S. anthropogenic Hg emissions, other sources both here and abroad also contribute significantly to the global atmospheric burden and U.S. deposition of Hg. It is estimated that the U.S. contributes 5 percent to global anthropogenic Hg and 2 percent the total global Hg pool.[2] However, as the U.S. Supreme Court has noted in decisions as recently as *Massachusetts* v. *EPA,* regarding the problem of climate change, it is not necessary to show that a problem will be entirely solved by the action being taken, nor that it is necessary to cure all ills before addressing those judged to be significant. *549 U.S. 497, 525 (2007).*

At the time it published the December 2000 Finding, EPA identified certain technologies capable of significantly reducing Hg and other HAP emissions. Since then, additional technologies and improvements to those previously identified have become available. These technologies are also often effective at reducing significantly the emissions of other conventional pollutants such as SO_2 and PM, thereby conferring even greater health co-benefits. As today's notice discusses further, the reductions expected from the adopted final rule will produce substantially greater co-benefits to health and the environment than they will cost to affected companies. We further believe that these reductions can be achieved without significantly affecting the availability and cost of electricity to

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[1] U.S. EPA. 1997. Mercury Study Report to Congress. EPA–452/R–97–003 December 1997.

[2] Based on 2005 U.S. emissions of 105 tons, and global emissions of 2,100 tons from UNEP. Mercury emissions are discussed more fully in Section III.D.1 of this preamble.

consumers. In those instances in which such concerns do arise, the Federal government will work with companies to ensure a reliable and reasonably-priced supply of electricity. Moreover, in its assessment of the impacts of today's proposed rule on jobs and the economy, EPA finds that more jobs will be created in the air pollution control technology production field than may be lost as the result of compliance with these proposed rules.

A number of EGUs operating today were built in the 1950s and 1960s, using now-obsolete and inefficient technologies. Today, new units are far more efficient in their production of electricity, their use of fuel, and the relative quantities of pollution emitted. To the extent that some of the oldest, least efficient, least controlled units are retired by companies who elect not to invest in controlling them, assessments included in the docket to today's notice of proposed rulemaking indicate that there will be a sufficient supply of electricity from newer units. In fact, one consequence of today's proposed rule, if adopted as a final rule, will be that the market for electricity in the U.S. will be more level and no longer skewed in favor of the higher polluting units that were exempted from the CAA at its inception on Congress' assumption that their useful life was near an end. Thus, this proposed rule will require companies to make a decision—control HAP emissions from virtually uncontrolled sources or retire these sometimes 60 year old units and shift their emphasis to more efficient, cleaner modern methods of generation, including modern coal-fired generation.

For the reasons summarized above and discussed in detail in this document, the standards being proposed today will be effective at significantly reducing emissions of Hg and an array of other toxic pollutants from coal- and oil-fired EGUs. In addition, as a result of the HAP reductions and co-benefits of these rules, many premature deaths from exposure to air pollution will be avoided by the application of controls that are well-known, broadly applied, and available. To the extent that isolated issues remain concerning the availability of electricity in some more remote parts of the country, we believe that EPA has the ability to work with companies making good faith efforts to comply with the standards so that consumers in those areas are not adversely affected.

Consistent with the recently issued Executive Order (EO) 13563, "Improving Regulation and Regulatory Review," we have estimated the cost and benefits of the proposed rule. The estimated net benefits of our proposed rule at a 3 percent discount rate are $48 to 130 billion or $42 to $120 billion at a 7 percent discount rate.

SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE PROPOSED RULE IN 2016

[Millions of 2007$] [a]

	3% Discount rate	7% Discount rate
Total Monetized Benefits [b]	$59,000 to $140,000	$53,000 to $130,000.
Hg-related Benefits [c]	$4.1 to $5.9	$0.45 to $0.89.
CO_2-related Benefits	$570	$570.
$PM_{2.5}$-related Co-benefits [d]	$58,000 to $140,000	$53,000 to $120,000.
Total Social Costs [e]	$10,900	$10,900.
Net Benefits	$48,000 to $130,000	$42,000 to $130,000.
Non-monetized Benefits	Visibility in Class I areas. Cardiovascular effects of Hg exposure. Other health effects of Hg exposure. Ecosystem effects. Commercial and non-freshwater fish consumption.	

[a] All estimates are for 2016, and are rounded to two significant figures. The net present value of reduced CO_2 emissions are calculated differently than other benefits. The same discount rate used to discount the value of damages from future emissions (SCC at 5, 3, 2.5 percent) is used to calculate net present value of SCC for internal consistency. This table shows monetized CO_2 co-benefits at discount rates at 3 and 7 percent that were calculated using the global average SCC estimate at a 3 percent discount rate because the interagency workgroup on this topic deemed this marginal value to be the central value. In section 6.6 of the RIA we also report the monetized CO_2 co-benefits using discount rates of 5 percent (average), 2.5 percent (average), and 3 percent (95th percentile).

[b] The total monetized benefits reflect the human health benefits associated with reducing exposure to MeHg, $PM_{2.5}$, and ozone.

[c] Based on an analysis of health effects due to recreational freshwater fish consumption.

[d] The reduction in premature mortalities from account for over 90 percent of total monetized $PM_{2.5}$ benefits.

[e] Social costs are estimated using the MultiMarket model, in order to estimate economic impacts of the proposal to industries outside the electric power sector. Details on the social cost estimates can be found in Chapter 9 and Appendix E of the RIA.

For more information on how EPA is addressing EO 13563, see the executive order discussion, later in the preamble.

B. Does this action apply to me?

The regulated categories and entities potentially affected by the proposed standards are shown in Table 1 of this preamble.

TABLE 1—POTENTIALLY AFFECTED REGULATED CATEGORIES AND ENTITIES

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 affected by this action. To determine whether your facility, company, business, organization, etc., would be regulated by this action, you should examine the applicability criteria in 40 CFR 60.40, 60.40Da, or 60.40c or in 40 CFR 63.9982. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

C. What should I consider as I prepare my comments to EPA?

Do not submit information containing CBI to EPA through *http://www.regulations.gov* or e-mail. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Docket ID EPA–HQ–OAR–2011–0044 (NSPS action) or Docket ID EPA–HQ–OAR–2009–0234 (NESHAP action). Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, 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 claimed as CBI. In addition to one complete version of the comment that includes 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. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

D. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this proposed rule will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of the proposed rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/.* The TTN provides information and technology exchange in various areas of air pollution control.

E. When would a public hearing occur?

EPA will hold three public hearings on this proposal. The dates, times, and locations of the public hearings will be announced separately. If you would like to present oral testimony at one of the hearings, please notify Ms. Pamela Garrett, Sectors Policies and Programs Division (C504–03), U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541–7966; e-mail: *garrett.pamela@epa.gov.* Persons wishing to provide testimony should notify Ms. Garrett at least 2 days in advance of the public hearings. For updates and additional information on the public hearings, please check EPA's Web site for this rulemaking, *http://www.epa.gov/ttn/atw/utility/utilitypg.html.*

II. Background Information on the NESHAP

In 1990, Congress substantially rewrote provisions of the CAA addressing emissions of HAP from large and small stationary sources in the U.S. Collectively, these sources emit into the air millions of pounds of HAP each year, chemicals that are known to cause or are suspected of causing cancer, birth defects, reproduction problems, and other serious health effects. Many of the sources that emit air toxics are located in urban areas, which generally include predominantly low income, minority or otherwise vulnerable communities, where dense populations mean that large numbers of people may be exposed.

Since 1990, EPA has promulgated regulations covering over 50 industrial sectors, requiring the use of available control technology and other practices to reduce emissions. These standards have reduced emissions of HAP from American industry by more than 60 percent. HAP emissions from smaller sources such as dry cleaners and auto body shops have declined by 30 percent, also due to CAA standards. Greater reductions are expected as greater numbers of smaller sources adopt pollution prevention, efficiency, or install control technologies to comply with EPA emission standards. Emissions from the mobile source sector have also been addressed. Controls for fuels and vehicles are expected to reduce selected HAP from vehicles by more than 75 percent by 2020.

EGUs are the most significant source of HAP in the country that remains unaddressed by Congress's air toxics program. EGUs emit multiple HAP of concern and are by far the largest remaining source of Hg, which is one of the more highly toxic chemicals on Congress's list of HAP and which, once released, stays in the environment permanently. Coal- and oil-fired EGUs also emit HAP such as As, other metals and acid gases in amounts significantly higher than almost any other industrial sector. They are located in nearly every state, and emissions from their stacks affect people nearby as well as hundreds of miles away.

Congress provided a specific path for EPA to regulate HAP emissions from EGUs. It gave explicit instructions about scientific studies EPA needed to develop and then consider in determining whether it was "appropriate and necessary" to regulate HAP emissions from EGUs. Congress anticipated that EPA would complete the studies by 1994. In 2000, EPA found that it was indeed "appropriate and necessary" to regulate HAP emissions from EGUs under section 112. In the decade that has passed since EPA made that finding, EGUs have continued to emit Hg and other HAP, and there are still no national limits on the amount of Hg and other HAP that EGUs can release into the air. And, although some plants have installed available and effective control technologies that reduce these emissions, there is no requirement for EGUs to control for Hg and other HAP.

As our new analyses demonstrate, it remains both appropriate and necessary to set standards for coal- and oil-fired EGUs to protect public health and the environment from the adverse effects of HAP emissions from EGUs. The Agency's appropriate and necessary finding was correct in 2000, and it remains correct today. EPA proposes to set standards for coal- and oil-fired EGUs that will reduce emissions of Hg, Ni and other metal HAP, acid gas HAP, and other harmful HAP. These standards are based on available control technologies and other practices already used by the better-controlled and lower-emitting EGUs. They are achievable, we believe they can be implemented without disruption to the reliable provision of electricity, and will deliver health protection across the U.S.

In this section, we provide an overview of the relevant statutory, regulatory, and litigation background.

A. Statutory Background

Congress enacted section 112 to address HAP emissions from stationary sources. Section 112 contains provisions specific to EGUs, which we will address in this preamble, but we begin with a summary of the overall structure and purpose of the section 112 program.

Prior to the 1990 Amendments, the CAA required EPA to regulate HAP solely on the basis of risk to human health. Legislative History of the CAA Amendments of 1990 (“Legislative History”), at 3174–75, 3346 (Comm. Print 1993). Congress was dissatisfied with the slow pace of exclusively risk-based regulation of HAP prior to 1990, however, and, as a result, substantially amended the CAA in 1990, setting forth a two-stage approach for regulating HAP emissions. Under the first stage, Congress directed EPA to issue technology-based emission standards for listed source categories. CAA sections 112 (c)–(d). In the second stage, which occurs “within eight years” of the imposition of the technology-based standards, EPA must consider whether residual risks remain after imposition of the MACT standards that warrant more stringent standards to protect human health or to prevent an adverse environmental effect. CAA section 112(f)(2)(A).

In addition to adopting this two-phased approach to standard-setting, Congress included a series of rigorous deadlines for EPA, including deadlines for listing categories and issuing emission standards for such categories. *See, e.g.,* CAA section 112(e)(1). Thus, in substantially amending CAA section 112 in 1990, Congress sought prompt and permanent reductions of HAP emissions from stationary sources—first through technology-based standards, and then further, as necessary, through risk-based standards designed to protect human health and the environment.

The criteria for regulation differ in section 112 depending on whether the source is a major source or an area source. A “major source” is any stationary source[3] or group of stationary sources at a single location and under common control that emits or has the potential to emit 10 tons or more per year of any HAP or 25 tons or more per year of any combination of HAP. *See* CAA 112(a)(1). An “area source” is any stationary source of HAP that is not a “major source.” *See* CAA 112(a)(2). For major sources, EPA must list a category under section 112(c)(1) if at least one stationary source in the category meets the definition of a major source.[4] For area sources, EPA must list if: (1) EPA determines that the category of area sources presents a threat of adverse effects to human health or the environment that warrants regulation under CAA section 112; or (2) the category of area sources falls within the purview of CAA section 112(k)(3)(B) (the Urban Area Source Strategy). *See* CAA section 112(c)(3).

Congress established a specific structure for determining whether to regulate EGUs under section 112.[5] Specifically, Congress enacted CAA section 112(n)(1).

In section 112(n)(1)(A), EPA is directed to conduct a study to evaluate the hazards to public health reasonably anticipated to occur as the result of HAP emissions from EGUs after imposition of the requirements of the CAA, and to report the results of such study to Congress by November 15, 1993 (Utility Study Report to Congress;[6] the “Utility Study”). We discuss this study further below in conjunction with the other studies Congress required be conducted with respect to EGUs under section 112(n)(1). The last sentence of section 112(n)(1)(A) provides that EPA shall regulate EGUs under CAA section 112 “if the Administrator finds such regulation is appropriate and necessary, after considering the results of the [Utility Study] * * *” Thus, section 112(n)(1)(A) governs how the Administrator decides whether to list EGUs for regulation under section 112. *See New Jersey,* 517 F.3d at 582 (“Section 112(n)(1) governs how the Administrator decides whether to list EGUs; it says nothing about delisting EGUs.”).

Once a source category is listed pursuant to section 112(c), the next step is for EPA to establish technology-based emission standards under section 112(d). Under section 112(d), EPA must establish emission standards for major sources that “require the maximum degree of reduction in emissions of the HAP subject to this section” that EPA determines is achievable taking into account certain statutory factors. These are referred to as “maximum achievable control technology” or “MACT” standards. The MACT standards for existing sources must be at least as stringent as the average emissions limitation achieved by the best performing 12 percent of existing sources in the category (for which the Administrator has emissions information) or the best performing 5 sources for source categories with less than 30 sources. *See* CAA section 112(d)(3)(A) and (B). This level of minimum stringency is referred to as the MACT floor, and EPA cannot consider cost in setting the floor. For new sources, MACT standards must be at least as stringent as the control level achieved in practice by the best controlled similar source. *See* CAA section 112(d)(3). EPA also must consider more stringent “beyond-the-floor” control options. When considering beyond-the-floor options, EPA must consider not only the maximum degree of reduction in emissions of HAP, but must take into account costs, energy, and nonair quality health and environmental impacts when doing so. *See Cement Kiln Recycling Coal.* v. *EPA,* 255 F.3d 855, 857–58 (D.C. Cir. 2001).

CAA section 112(d)(4) authorizes EPA to set a health-based standard for a limited set of HAP for which a health threshold has been established, and that standard must provide for “an ample margin for safety.” 42 U.S.C. 7412(d)(4). As these standards are potentially less stringent than MACT standards, the Agency must have detailed information on HAP emissions from the subject sources and sources located near the subject sources before exercising its discretion to set such standards.

For area sources, section 112(d)(5) authorizes EPA to issues standards or requirements that provide for the use of generally available control technologies (GACT) or management practices in lieu of promulgating standards pursuant to sections 112(d)(2) and (3).

As noted above, Congress required that various reports concerning EGUs be completed. The first report, the Utility Study, required EPA to evaluate the hazards to public health reasonably anticipated to occur as the result of HAP emissions from EGUs after imposition of the requirements of the CAA. This report was required by November 15, 1993. The second report, due on November 15, 1994, directed EPA to “conduct a study of mercury emissions from [EGUs], municipal waste combustion units, and other sources, including area sources.” *See* CAA section 112(n)(1)(B). In conducting the Mercury study Congress directed EPA to “consider the rate and mass of emissions, the health and environmental effects of such emissions, technologies which are available to control such emissions, and the costs of such technologies.” *Id.* EPA completed both of these reports by 1998.

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[3] A “stationary source” of HAP is any building, structure, facility or installation that emits or may emit any air pollutant. See CAA Section 112(a)(3).

[4] Congress required EPA to publish a list of categories and subcategories of major sources and area sources by November 15, 1991. See CAA 112(c)(1) & (c)(3). EPA published the initial list on July 16, 1992. See 57 FR 31576, July 16, 1992. EPA did not include EGUs on the initial section 112(c) list because Congress required EPA to conduct and consider the results of the study required by section 112(n)(1)(A) before regulating these units. At the time of the initial listing, EPA had not completed the study required by section 112(n)(1)(A).

[5] “Electric utility steam generating unit” is defined as any “fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale.” See CAA 112(a)(8).

[6] US EPA. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units —Final Report to Congress. EPA–453/R–98–004a. February 1998.

The last required report was to be completed by the National Institute of Environmental Health Sciences (NIEHS) and submitted to Congress by November 15, 1993. CAA section 112(n)(1)(C) directed NIEHS to conduct "a study to determine the threshold level of Hg exposure below which adverse human health effects are not expected to occur." In conducting this study, NIEHS was to determine "a threshold for mercury concentrations in the tissue of fish which may be consumed (including consumption by sensitive populations) without adverse effects to public health." Id. NIEHS submitted this Report to Congress in August, 1995.

In addition, Congress, in conference report language associated with EPA's fiscal year 1999 appropriations, directed EPA to fund the National Academy of Sciences (NAS) to perform an independent evaluation of the available data related to the health impacts of MeHg ("Toxicological Effects of Methylmercury," hereinafter, NAS Study or MeHg Study).[7] H.R. Conf. Rep. No. 105–769, at 281–282 (1998). Specifically, NAS was tasked with advising EPA as to the appropriate reference dose (RfD) for MeHg, which 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. 65 FR 79826. In that same conference report, Congress indicated that EPA should not make the appropriate and necessary regulatory determination for Hg emissions until EPA had reviewed the results of the NAS Study. *See* H.R. Conf. Rep. No. 105–769, at 281–282 (1998).

The NAS Study evaluated the same issues as those required to be considered under section 112(n)(1)(C). The NAS Study was completed 5 years after the NIEHS Study, and, thus, considered additional information not available to NIEHS. Because Congress required that the same issues be addressed in both the NAS and NIEHS Studies and the NAS Study was issued after the NIEHS study, we discuss, for purposes of this document, the content of the NAS Study, as opposed to the NIEHS Study.

B. Regulatory and Litigation Background

EPA conducted the studies required by section 112(n)(1) concerning utility HAP emissions. Prior to issuance of the Mercury Study, EPA engaged in two extensive external peer reviews of the document. Although EPA missed the statutory deadline for completing the studies, the Mercury Study and the Utility Study were complete by 1998. The NIEHS study was completed in 1995, and the NAS Study was completed in 2000.

In December 2000, after considering public input, the studies required by section 112(n)(1) and other relevant information, including Hg emissions data from EGUs, EPA determined that it was appropriate and necessary to regulate EGUs under CAA section 112. Based on that determination, the Agency listed such units for regulation under section 112(c).

Pursuant to a settlement agreement, the deadline for issuing emission standards was March 15, 2005. However, instead of issuing emission standards pursuant to section 112(d), on March 15, 2005, EPA delisted EGUs, finding that it was neither appropriate nor necessary to regulate such units under section 112. That attempt to delist was subsequently invalidated by the DC Circuit Court.

1. Studies Related to HAP Emissions From EGUs

a. The Utility Study

EPA issued the Utility Study in February 1998, over 4 years after the statutory deadline. The Utility Study included numerous analyses. EPA first collected HAP emissions test data from 52 EGUs, including a range of coal-, oil-, and natural gas-fired units, and the test data along with facility specific information were used to estimate HAP emissions from all 684 utility facilities. EPA determined that 67 HAP were emitted from EGUs. In addition, the study evaluated HAP emissions based on two scenarios: (1) 1990 base year; and (2) 2010 projected emissions. The 2010 scenario was selected to meet the section 112(n)(1)(A) mandate to evaluate hazards "after imposition of the requirements of the Act." EPA also considered potential control strategies for the identified HAP consistent with section 112(n)(1)(A).

EPA evaluated exposures, hazards, and risks due to HAP emissions from coal-, oil-, and natural gas-fired EGUs. EPA conducted a screening level assessment of all 67 HAP to prioritize the HAP for further analysis. A total of 14 HAP were identified as priority HAP that would be further assessed. Twelve HAP (As, beryllium (Be), Cd, Cr, manganese (Mn), Ni, HCl, HF, acrolein, dioxins, formaldehyde, and radionuclides) were identified as a priority for further assessment based on inhalation exposure and risk. Six HAP (Hg, radionuclides, As, Cd, Pb, and dioxins) were considered a priority for multipathway assessment of exposure and risk.

Based on the inhalation estimates for the priority HAP, EPA determined that As and Cr emissions from coal-fired EGUs and Ni emissions from oil-fired EGUs contributed most to the potential cancer related inhalation risks, but those risks were not high. The non-cancer risk assessment due to inhalation exposure indicated exposures were well below the reference levels.

The Agency also conducted multipathway assessments for the six HAP identified above. Based on these analyses, EPA determined that Hg from coal-fired EGUs was the HAP of greatest potential concern. In addition, the screening multipathway assessments for dioxins and As suggested that these two HAP were of potential for multipathway risk.

In addition to the 1990 analysis, EPA also estimated emissions and inhalation risks for the year 2010. HAP emissions from coal-fired utilities were predicted to increase by 10 to 30 percent by the year 2010. Predicted changes included the installation of scrubbers for a small number of facilities, the closing of a few facilities, and an increase in fuel consumption of other facilities. For oil-fired plants, emissions and inhalation risks were estimated to decrease by 30 to 50 percent by the year 2010, primarily due to projected reductions in use of oil for electricity generation. Multipathway risks for 2010 were not assessed.

In estimating future emissions from EGUs, EPA primarily evaluated the effect of implementation of the Acid Rain Program (ARP) on HAP emissions from EGUs. The 2010 scenario also included estimated changes in emissions resulting from projected trends in fuel choices and power demands.

Table 2 of this preamble presents estimated emissions for a subset of priority HAP for 1990 and 2010.

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[7] National Research Council (NAS). 2000. Toxicological Effects of Methylmercury. Committee on the Toxicological Effects of Methylmercury, Board on Environmental Studies and Toxicology, National Research Council. Many of the peer-reviewed articles cited in this section are publications originally cited in the NAS report.

TABLE 2—NATIONWIDE EMISSIONS FOR SIX PRIORITY HAP, TPY

HAP	Coal		Oil		Natural gas	
	1990	2010	1990	2010	1990	2010
Arsenic	61	71	5	3	0.15	0.25
Chromium	73	87	4.7	2.4	....	....
Mercury	46	60	0.25	0.13	0.0015	0.024
Nickel	58	69	390	200	2.2	3.5
Hydrogen chloride	143,000	155,000	2,900	1,500	NM	NM
Hydrogen fluoride	20,000	26,000	140	73	NM	NM

Numerous potential alternative control strategies for reducing HAP emissions from EGUs were identified. These included pre-combustion controls (*e.g.,* fuel switching, coal cleaning), post combustion controls (*e.g.,* PM controls, SO_2 controls), and improving efficiency in supply or demand. For example, coal cleaning tends to remove at least some of all the trace metals. EPA also concluded that PM controls tend to effectively remove the trace metals (excluding Hg). The Utility Study also found that flue gas desulfurization (FGD) units were less effective at removing trace metals and exhibited more variability in removal of those metals than PM control, but FGD were more effective at reducing acid gas HAP.

b. The Mercury Study

EPA issued the Mercury Study in December 1997, 3 years after the statutory deadline. The Mercury Study assessed the magnitude of U.S. Hg emissions by source, the health and environmental implications of those emissions, and the availability and cost of control technologies.

According to the Mercury Study, Hg cycles in the environment as a result of natural and human (anthropogenic) activities. Most of the Hg in the atmosphere is elemental Hg vapor, which circulates in the atmosphere for up to a year, and, hence, can be widely dispersed and transported thousands of miles from likely sources of emission. The Mercury Study also found that most of the Hg in water, soil, sediments, or plants and animals is in the form of inorganic Hg salts and organic forms of Hg (*e.g.,* MeHg). The inorganic form of Hg, when either bound to airborne particles or in a gaseous form, is readily removed from the atmosphere by precipitation and is also dry deposited. Wet deposition is the primary mechanism for transporting Hg from the atmosphere to surface waters and land. Even after it deposits, Hg commonly is emitted back to the atmosphere either as a gas or associated with particles, to be re-deposited elsewhere.

The Mercury Study estimated that in 1994–1995, anthropogenic U.S. Hg emissions were about 158 tons annually. Roughly 87 percent of those emissions were from combustion sources, including waste and fossil fuel combustion. According to the Mercury Study, current anthropogenic emissions were only one part of the Hg cycle. The Mercury Study noted that current releases from human activities were adding to the Hg reservoirs that already exist in land, water, and air, both naturally and as a result of prior human activities. The Mercury Study concluded that the flux of Hg from the atmosphere to land or water at any one location is comprised of contributions from the natural global cycle, including re-emissions from the oceans, international sources, regional sources, and local sources.

The Mercury Study further described a computer simulation of long-range transport of Hg, which suggested that about one-third (approximately 52 tons) of U.S. anthropogenic emissions are deposited, through wet and dry deposition, within the lower 48 states. The remaining two-thirds (approximately 107 tons) was estimated to be transported outside of U.S. borders where it would diffuse into the global reservoir. The computer simulation further suggested that another 35 tons of Hg from the global reservoir outside the U.S. was deposited annually in the U.S. for a total deposition in the U.S. of roughly 87 tons per year (tpy).

The Mercury Study also found that fish consumption dominates the pathway for human and wildlife exposure to MeHg and that there was a plausible link between anthropogenic releases of Hg from industrial and combustion sources in the U.S. and MeHg in fish. In the Mercury Study, EPA explained that, given the current scientific understanding of the environmental fate and transport of this element, it was not possible to quantify how much of the MeHg in fish consumed by the U.S. population results from U.S. anthropogenic emissions, as compared to other sources of Hg (such as natural sources and re-emissions from the global pool).

The Mercury Study noted that those who regularly and frequently consume large amounts of fish—either marine species that typically have much higher levels of MeHg than other species, or freshwater fish that have been affected by Hg pollution—are more highly exposed. Because the developing fetus may be the most sensitive to the effects from MeHg, women of child-bearing age were the population of greatest interest. EPA concluded in the Mercury Study that approximately 7 percent of women of child-bearing age (*i.e.,* between the ages of 15 and 44) were exposed to MeHg at levels exceeding the RfD.

Finally, the Mercury Study concluded that piscivorous (fish-eating) birds and mammals were more highly exposed to Hg than any other known component of aquatic ecosystems, and that adverse effects of Hg on fish, birds and mammals include death, reduced reproductive success, impaired growth and development, and behavioral abnormalities. The Mercury Study also evaluated Hg emissions control technologies and the costs of such technologies.

c. The NAS Methylmercury Study

In the appropriations report for EPA's fiscal 1999 funding, Congress directed EPA to fund the NAS to perform an independent study on the toxicological effects of MeHg and to prepare recommendations on the establishment of a scientifically appropriate MeHg exposure RfD. In response, EPA contracted with NAS, which conducted an 18-month study of the available data on the health effects of MeHg and reported its findings to EPA in July 2000.

The EPA included four charges to NAS: (1) Evaluate the body of evidence that led to EPA's current RfD for MeHg, and on the basis of available human epidemiological and animal toxicity data, determine whether the critical study, end point of toxicity, and uncertainty factors used by EPA in the derivation of the RfD for MeHg are scientifically appropriate, including consideration of sensitive populations; (2) evaluate any new data not considered in the Mercury Study that could affect the adequacy of EPA's MeHg RfD for protecting human health; (3) consider exposures in the environment relevant to evaluation of likely human exposures (especially to sensitive subpopulations and especially from consumption of fish that contain MeHg), and include in the evaluation a focus on those elements of exposure relevant to the establishment of an appropriate RfD; and (4) identify data gaps and make recommendations for future research.

The NAS held both public and closed sessions wherein they evaluated data and presentations from government agencies, trade organizations, public interest groups, and concerned citizens. The NAS also evaluated new findings that had emerged since the development of EPA's 1995 RfD and met with the investigators of major ongoing epidemiological studies.

The NAS Study concluded that the value of EPA's 1995 RfD for MeHg, 0.1 micrograms per kilogram (μg/kg) per day, was a scientifically appropriate level for the protection of public health. The NAS Study further concluded that data from both human and animal studies indicated that the developing nervous system was a sensitive target organ for low-dose MeHg exposure. The NAS Study indicated that there was evidence that exposure to MeHg in humans and animals can have adverse effects on both the developing and adult cardiovascular system. Some of the studies observed adverse cardiovascular effects at or below MeHg exposure levels associated with neurodevelopmental effects. The weight of evidence for carcinogenicity of MeHg was inconclusive. There was also evidence from animal studies that the immune and reproductive systems are sensitive targets for MeHg toxicity.

According to the NAS Study, the estimates of MeHg exposures in the U.S. population indicated that the risk of adverse effects from then-current MeHg exposures in the majority of the population was low. However, the NAS Study concluded that individuals with high MeHg exposures from frequent fish consumption might have little or no margin of safety (*i.e.,* exposures of high-end consumers are close to those with observable adverse effects). The NAS Study also noted that the population at highest risk was the children of women who consumed large amounts of fish and seafood during pregnancy. The NAS Study further concluded that the impact on that population was likely to be sufficient to result in an increase in the number of children who struggle to keep up in school and might require remedial classes or special education.

2. EPA's December 2000 Appropriate and Necessary Finding

On December 20, 2000, EPA issued a finding pursuant to CAA section 112(n)(1)(A) that it was appropriate and necessary to regulate coal- and oil-fired EGUs under section 112 and added such units to the list of source categories subject to regulation under section 112(d). In making that finding, EPA considered the Utility Study, the Mercury Study, the NAS Study, and certain additional information, including information about Hg emissions from coal-fired EGUs that EPA obtained pursuant to an information collection request (ICR) under the authority of section 114 of the CAA. 65 FR 79826–27. EPA collected data on the Hg content of coal from all coal-fired EGUs for the calendar year 1999 and Hg emissions stack test data for certain coal-fired EGUs. 65 FR 79826. EPA also solicited data from the public through a February 29, 2000, notice (65 FR 10783). The public had an opportunity to provide their views on what the section 112(n)(1)(A) appropriate and necessary regulatory finding should be at a public meeting in Chicago, Illinois, on June 13, 2000 (65 FR 18,992). 65 FR 79826.

In the December 2000 notice, EPA explained that it evaluated EGUs based on the type of fossil fuel combusted (*i.e.,* coal, oil, and natural gas). The December 2000 Finding focused primarily on Hg emissions from coal-fired EGUs. Mercury was determined to be the HAP of greatest concern in the Utility Study. In evaluating Hg emissions from coal-fired EGUs, EPA stated that the quality of the Hg data available in 2000 was considerably better than the data available for the Utility Study because of the results of the 1999 ICR. The new data also corroborated the Hg emissions estimates in the study. 65 FR 79828. In the finding, EPA explained that Hg is highly toxic and persistent and that it bioaccumulates in the food chain; that Hg air emissions from all sources, including EGUs, deposit on the land where the Hg may transform into MeHg, which is the primary type of Hg that accumulates in fish tissue; and that eating Hg contaminated fish was the primary route of exposure for humans. 65 FR 79827. The potential hazard of most concern was determined to be consumption by subsistence fish-eating populations and women of childbearing age because of the adverse effects that Hg poses to the developing fetus. 65 FR 79827. Finally, EPA noted that approximately 7 percent of women of child bearing age were exposed to levels of MeHg that exceeded the RfD. 65 FR 79827.

EPA further estimated that about 60 percent of the total Hg deposited in the U.S. came from anthropogenic air emissions originating in the U.S. and that EGUs contributed approximately 30 percent of those anthropogenic air emissions. 65 FR 79827. Based on the record before the Agency at the time, EPA determined that there was a plausible link between Hg emissions from EGUs and MeHg in fish and that Hg emissions from EGUs were a threat to public health and the environment. 65 FR 79827.

In discussing the non-Hg HAP from coal- and oil-fired EGUs, EPA stated that HAP metals such as As, Cr, Ni, and Cd are of potential concern for carcinogenic effects. 65 FR 79827. EPA acknowledged that the risk assessments conducted for these HAP indicated that cancer risks were not high, but the Agency could not conclude the potential concern for public health was eliminated for those metals. 65 FR 79827. EPA further stated that dioxins, HCl, and HF were of potential concern and could be evaluated further during the regulatory development process. 65 FR 79827. EPA also concluded that the remaining HAP evaluated in the Utility Study did not appear to be a public health concern, but the Agency noted that there were limited data and uncertainties associated with this conclusion, and we stated that future data collection efforts could identify additional HAP of potential concern. 65 FR 79827.

EPA also explained that, consistent with Congress's direction in section 112(n)(1)(A), we considered the alternative control strategies available to control the HAP emissions that may warrant control. We noted that currently available controls for criteria pollutants would also be effective at controlling the HAP emissions from EGUs. 65 FR 79828.

EPA then made nine specific conclusions based on the information in the record, some of which are summarized above. 65 FR 79829–30. Based on those conclusions, EPA found that it was "appropriate" to regulate HAP emissions from coal- and oil-fired EGUs because EGUs "are the largest domestic source of Hg emissions, and Hg in the environment presents significant hazards to public health and the environment." 65 FR 79830. EPA noted that the NAS Study confirmed EPA's own research concluding that "mercury in the environment presents a significant hazard to public health." 65

FR 79830. EPA explained that it was appropriate to regulate HAP emissions from coal- and oil-fired units because it had identified certain control options that, it anticipated, would effectively reduce HAP from such units. 65 FR 79830. In discussing its findings, EPA also noted that uncertainties remained concerning the extent of the public health impact from HAP emissions from oil-fired units. 65 FR 79830.

Once EPA determined that it was "appropriate" to regulate coal- and oil-fired EGUs under CAA section 112, EPA next concluded that it was also "necessary" to regulate HAP emissions from such 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 Utility RTC and confirmed by the NAS Study, and which section 112 is intended to address." 65 FR 79830.

For natural gas-fired EGUs, EPA found that regulation of HAP emissions "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 utility RTC." 65 FR 79831.

In light of the positive appropriate and necessary determination, EPA in December 2000 listed coal- and oil-fired EGUs on the section 112(c) source category list. 65 FR 79831.

3. The 2005 Action

On March 29, 2005, EPA issued the Section 112(n) Revision Rule ("2005 Action") that has since been vacated by the DC Circuit Court. In that rule, EPA reversed the December 2000 Finding and concluded that it was neither appropriate nor necessary to regulate coal- and oil-fired EGUs under section 112 and delisted such units from the section 112(c) source category list. 70 FR 15994. EPA took the position that the December 2000 Finding lacked foundation and that new information confirmed that it was not appropriate or necessary to regulate coal- and oil-fired EGUs under CAA section 112.

In the final rule, EPA provided a detailed interpretation of section 112(n)(1)(A), including the terms "appropriate" and "necessary," as those terms relate to the regulation of EGUs under section 112. In interpreting the statute, EPA recognized that section 112(n)(1)(A) provided no explicit guidance for determining whether regulation of EGUs is appropriate and necessary. As such, EPA concluded that Congress' direction on the Utility Study provided the only guidance about the substance of the appropriate and necessary finding. Accordingly, EPA extrapolated from Congress' description of the Utility Study when interpreting the terms appropriate and necessary.

Among other things, the Agency interpreted the focus on public health in the Utility Study as precluding EPA from considering environmental impacts. 70 FR 15998. EPA also looked at Congress' focus on EGU emissions in the Study and took the position that EPA could only consider hazards to public health that could be traced directly to HAP emissions from EGUs in assessing whether it was appropriate to regulate. EPA declined to consider the potential adverse public health impacts that may occur as the result of the combination of EGU HAP emissions and HAP emissions from other sources. 70 FR 15998.

In making the determination as to whether it was appropriate to regulate, EPA analyzed whether the level of HAP emissions from EGUs remaining after imposition of the requirements of the CAA would result in a hazard to public health. EPA concluded that if the HAP emissions remaining after imposition of the requirements of the CAA do not pose a hazard to public health, then regulation under section 112 is not appropriate. EPA also maintained that even if it identified a hazard to public health, regulation may still not be "appropriate" based on other relevant factors, such as the cost effectiveness of regulation under section 112. 70 FR 15600.

In the 2005 Action, EPA interpreted the term "necessary" to mean "that it is necessary to regulate EGUs under section 112 only if there are no other authorities available under the CAA that would, if implemented, effectively address the remaining HAP emissions from EGUs." 70 FR 16001.

Applying these interpretations, the Agency stated that it was neither appropriate nor necessary to regulate HAP emissions from EGUs. The Agency took the position that the December 2000 appropriate finding lacked foundation because the finding was overbroad to the extent that it relied on environmental effects. 70 FR 16002. The EPA next stated that the appropriate determination in the December 2000 Finding lacked foundation because EPA did not fully consider the Hg reductions that would result after imposition of the requirements of the CAA and that new information showed that the level of Hg emissions from EGUs remaining after imposition of the requirements of the CAA do not pose a hazard to public health. 70 FR 16003–4. Specifically, EPA pointed to the promulgation of the Clean Air Interstate Rule (CAIR), issued pursuant to CAA section 110(a)(2)(D), and the Clean Air Mercury Rule (CAMR),[8] issued pursuant to section 111, and, based on modeling, determined that CAIR, and independently CAMR, could be expected to reduce Hg emissions to levels that would not cause a hazard to public health. Therefore, EPA concluded that it was not appropriate to regulate EGUs under section 112. We note that CAMR was vacated by the D.C. Circuit Court in *New Jersey* v. *EPA,* and that CAIR was remanded to the Agency in *North Carolina* v. *EPA,* 531 F.3d 896, *modified on reh'g,* 550 F.3d 1176 (DC Cir. 2008).

As to the necessary finding, EPA took the position that the December 2000 Finding was in error because EPA did not, at the time, examine whether there were any CAA provisions other than section 112 that, if implemented, would address any identified hazards to public health from HAP emissions from EGUs. 70 FR 16004. Specifically, EPA stated that the error existed because EPA did not consider CAA sections 110(a)(2)(D) and 111 and that, considering actions under these sections, hazard to public health from EGUs would be reduced. 70 FR 16005.

EPA also determined that it was not appropriate and necessary to regulate coal-fired EGUs on the basis of non-Hg HAP emission or oil-fired EGUs on the basis of Ni and non-Ni HAP. 70 FR 16007.

4. Litigation History

Shortly after issuance of the December 2000 Finding, an industry group challenged that finding in the DC Circuit Court. *UARG* v. *EPA,* 2001 WL 936363, No. 01–1074 (DC Cir. July 26, 2001). The DC Circuit Court dismissed the lawsuit holding that it did not have jurisdiction because section 112(e)(4) provides, in pertinent part, that "no action of the Administrator * * * listing a source category or subcategory under subsection (c) of this section *shall be a final agency action subject to judicial review,* except that any such action may be reviewed under section 7607 of (the CAA) when the Administrator issues emission standards for such pollutant or category." (*emphasis added*)

Environmental groups, States, and tribes challenged the 2005 Action and CAMR. Among other things, the environmental and state petitioners argued that EPA could not remove EGUs

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[8] On May 18, 2005, EPA issued the Clean Air Mercury Rule (CAMR). 70 FR 28606. That rule established standards of performance for emissions of mercury from new and existing coal-fired EGUs pursuant to CAA section 111.

from the section 112(c) source category list without following the requirements of section 112(c)(9).

On February 8, 2008, the DC Circuit Court vacated both the 2005 Action and CAMR. The DC Circuit Court held that EPA failed to comply with the requirements of section 112(c)(9) for delisting source categories. Specifically, the DC Circuit Court held that section 112(c)(9) applies to the removal of "any source category" from the section 112(c) list, including EGUs. The DC Circuit Court rejected the argument that EPA has the inherent authority to correct its mistakes, finding that, by enacting section 112(c)(9), Congress limited EPA's discretion to reverse itself and remove source categories from the section 112(c) list. The DC Circuit Court found that EPA's contrary position would "nullify § 112(c)(9) altogether." *New Jersey*, 517 F.3d at 583. The DC Circuit Court did not reach the merits of petitioners' arguments on CAMR, but vacated CAMR for existing sources because coal-fired EGUs were listed sources under section 112. The DC Circuit Court reasoned that even under EPA's own interpretation of the CAA, regulation of existing sources' Hg emissions under section 111 was prohibited if those sources were a listed source category under section 112.[9] The DC Circuit Court vacated and remanded CAMR for new sources because it concluded that the assumptions EPA made when issuing CAMR for new sources were no longer accurate (*i.e.,* that there would be no section 112 regulation of EGUs and that the section 111 standards would be accompanied by standards for existing sources). *Id.* at 583–84. Thus, CAMR and the 2005 appropriate and necessary finding became null and void.

On December 18, 2008, several environmental and public health organizations ("Plaintiffs")[10] filed a complaint in the DC District Court (Civ. No. 1:08-cv-02198 (RMC)) alleging that the Agency had failed to perform a nondiscretionary duty under CAA section 304(a)(2), by failing to promulgate final section 112(d) standards for HAP from coal- and oil-fired EGUs by the statutorily mandated deadline, December 20, 2002, 2 years after such sources were listed under section 112(c). EPA settled that litigation. The consent decree resolving the case requires EPA to sign a notice of proposed rulemaking setting forth EPA's proposed section 112(d) emission standards for coal- and oil-fired EGUs by March 16, 2011, and a notice of final rulemaking by November 16, 2011.

III. Appropriate and Necessary Finding

As required by the CAA, we determined in December 2000, and confirm that finding here, that it is appropriate to regulate emissions of Hg and other HAP from EGUs because manmade emissions of those pollutants pose hazards to public health and the environment, and EGUs are the largest or among the largest contributors of many of those HAP. It is necessary to do so for a variety of reasons, including that hazards to public health and the environment from EGUs remain after imposition of the requirements of the CAA.

In this section, we address the Agency's determination that it is appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112. We first provide our interpretation of the critical terms in CAA section 112(n)(1). As shown below, these interpretations are wholly consistent with the CAA and the December 2000 Finding. We then demonstrate that the December 2000 Finding was valid at the time it was made based on the information available to the Agency at that time. Finally, we explain that, although not required, we recently conducted additional technical analyses given that several years have passed since the December 2000 Finding was issued. Those analyses include both a quantitative and qualitative assessment of the hazards to public health and a qualitative analysis of hazards to the environment associated with Hg and non-Hg HAP from EGUs. The analyses confirm that it remains appropriate and necessary today to regulate EGUs under CAA section 112. We also explain why these analyses and the other information currently before the Agency confirm that regulation of EGUs under section 112 is appropriate and necessary. Accordingly, such units are properly listed pursuant to section 112(c).

A. Regulating EGUs Under CAA Section 112

CAA section 112(n)(1)(A) requires the Agency to regulate EGUs under section 112 "if the Administrator finds such regulation is *appropriate* and *necessary* after considering the results of the [Utility Study]." (*emphasis added*). Congress did not define the phrase "appropriate and necessary" in section 112(n)(1)(A). Rather, Congress expressly delegated to the Agency the authority to interpret and apply those terms. *See Chevron U.S.A. Inc.* v. *Natural Resources Defense Council, Inc.,* 467 U.S. 837, 843–44 (1984) (the Agency's interpretation of statutory terms is entitled to considerable deference as long as it is a reasonable reading of the statute).

Courts have interpreted the terms "appropriate" and "necessary" in other provisions of the CAA and other statutes, and concluded that those terms convey upon the Agency a wide degree of discretion. *See, e.g., National Association of Clean Air Act Agencies* v. *EPA,* 489 F.3d 1221, 1229 (DC Cir. 2007) (finding "both explicit and extraordinarily broad" the Administrator's authority under CAA section 231(a)(3) to "issue regulations with such modifications *as he deems appropriate.*") (*emphasis in original*); *see* also *Cellular Telecommunications & Internet Association, et al.* v. *FCC,* 330 F.3d 502, 510 (DC Cir. 2003), (finding that "[c]ourts have frequently interpreted the word 'necessary' to mean less than absolutely essential, and have explicitly found that a measure may be 'necessary' even though acceptable alternatives have not been exhausted." (quoting *Natural Res. Def. Council* v. *Thomas,* 838 F.2d 1224, 1236 (DC Cir. 1998) (internal quotation marks omitted)).

We evaluate the terms "appropriate" and "necessary" within the statutory context in which they appear to determine the meaning of the words. *See Cellular Telecommunications,* 330 F.3d at 510 (finding that "it is crucial to understand the context in which the word [necessary] is used in order to comprehend its meaning.") (citations omitted). In this case, we look for guidance in section 112 generally, and focus specifically on section 112(n)(1), which addresses EGUs.

1. Statutory Framework for Evaluating EGUs

As explained above, Congress, concerned by the slow pace of EPA's regulation of HAP, "altered section 112 by eliminating much of EPA's discretion in the process." *New Jersey,* 517 F.3d at 578 (citations omitted). We describe above the two-phased approach to standard setting. Also, relevant, however, is that Congress set very strict deadlines for listing source categories and issuing emission standards for such

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[9] In CAMR and the 2005 Action, EPA interpreted section 111(d) of the Act as prohibiting the Agency from establishing an existing source standard of performance under section 111(d) for any HAP emitted from a particular source category, if the source category is regulated under section 112.

[10] American Nurses Association, Chesapeake Bay Foundation, Inc., Conservation Law Foundation, Environment America, Environmental Defense Fund, Izaak Walton League of America, Natural Resources Council of Maine, Natural Resources Defense Council, Physicians for Social Responsibility, Sierra Club, The Ohio Environmental Council, and Waterkeeper Alliance, Inc.

categories. *See e.g.,* Section 112(c)(6), 112(e)(1); *New Jersey,* 517 F.3d at 578 (noting that "EPA was required to list and to regulate, on a prioritized schedule" all categories and subcategories of major and area sources). Thus, in substantially amending section 112 of the CAA in 1990, Congress sought prompt and permanent reductions of HAP emissions from stationary sources—first through technology-based standards, and then further, as necessary, through risk-based standards designed to protect human health and the environment.

Congress' focus on protecting public health and the environment from EGU HAP emissions is reflected in section 112(n)(1), titled "[e]lectric utility steam generating units." That section directs EPA to evaluate HAP emissions from EGUs. In addition to directing EPA to regulate EGUs under section 112 if it determines that it is appropriate and necessary to do so, section 112(n)(1) requires the completion of three studies related to HAP emissions from EGUs. Those studies include: (1) The Utility Study pursuant to section (n)(1)(A); (2) the Mercury Study pursuant to section (n)(1)(B); and (3) the NIEHS Study (NAS Study) pursuant to section 112(n)(1)(C).[11]

These studies are described above, in detail. In summary, for the Utility Study, Congress required EPA to evaluate the hazards to public health that are reasonably anticipated to occur as the result of EGU emissions following imposition of the requirements of the CAA. Congress also directed EPA to identify alternative control strategies for those HAP that may warrant regulation under section 112.

The Mercury Study required by section 112(n)(1)(B) is both broader and narrower in scope, as compared to the Utility Study. For example, the Mercury Study is narrower in scope, in that it focuses solely on the impacts from Hg emissions, as opposed to all HAP. The Mercury Study is broader in scope, however, in two important respects. First, Congress required EPA to consider environmental effects in addition to health effects. Second, Congress required the Agency to consider the cumulative effects of Hg from all sources, including EGUs. In considering the cumulative effects of Hg, the Agency was not required to apportion the cause of any adverse effects among the various sources of Hg. Both the Utility and Mercury Studies considered the control technologies available to control Hg emissions, but only the Mercury Study called for the evaluation of the costs of such controls. Section 112(n)(1)(B).

EPA believes that Congress directed the Agency to conduct the Utility Study so that the Agency would understand the hazards to public health posed by HAP emissions from EGUs alone, and consider whether any hazards that were identified would be addressed through imposition of the requirements of the CAA applicable to EGUs at that time. Congress provided EPA an additional year to examine the impacts of EGU emissions of Hg on health and the environment in combination with other sources of Hg emissions.

The NAS Study required by section 112(n)(1)(C), which was due at the same time as the Utility Study, was to focus on Hg only and the adverse human health effects associated with Hg. The statute directed the determination of the threshold level of Hg below which adverse effects to human health are not expected to occur. The statute further directed the determination of the threshold for Hg concentrations in the tissue of fish which may be consumed, including by sensitive populations, without adverse effects to public health. Here, unlike the Utility Study and the Mercury Study, the statute specifically requires an evaluation of the adverse human health effects of Hg on sensitive populations.

The remaining critical element of section 112(n)(1) is the direction to EPA to determine whether it is appropriate and necessary to regulate EGUs under section 112, considering the results of the Utility Study. Although the Utility Study is a condition precedent to making the appropriate and necessary determination, nothing in section 112(n)(1)(A) precludes the Agency from considering other information in making that determination.

Taken together, we believe these provisions provide a framework for the Agency's determination of whether to regulate HAP emissions from EGUs under section 112. Through these provisions, Congress sought a prompt review and evaluation of the hazards to public health and the environment associated with Utility HAP emissions. This prompt consideration of health and environmental impacts is consistent with the strict deadlines Congress imposed in section 112 on all other source categories. *See infra.*

Section 112(n)(1)(B) is direct evidence that Congress was concerned with environmental effects and cumulative impacts of HAP emissions from EGUs and other sources, particularly with regard to the bio-accumulative HAP Hg. Section 112(n)(1)(C) provides further evidence that Congress was concerned with limiting HAP emissions from EGUs to a level that protects sensitive populations. We believe the scope of the Utility Study was limited to HAP emissions from EGUs and hazards to public health, not because Congress was unconcerned with adverse environmental effects or the cumulative impact of HAP emissions, but because the Utility Study, as required, was a significant undertaking in itself and Congress wanted the Agency to complete the study within 3 years. Thus, section 112(n)(1) reveals, among other things, Congress' concern for the health and environmental effects of HAP emissions from EGUs, both alone and in conjunction with other sources, the impact of Hg emissions from EGUs, and the availability of controls to address HAP emissions from EGUs.

Finally, significantly, nowhere in section 112(n)(1) does Congress require the consideration of costs in assessing health and environmental impacts. The only reference to costs is in section 112(n)(1)(B) and that reference required the Agency to consider the costs of emission reduction controls for Hg.

2. Interpretation of Key Terms

Section 112(n)(1)(A) itself provides no clear standard to govern EPA's analysis and determination of whether it is "appropriate and necessary" to regulate utilities under section 112. The statute simply requires EPA to regulate EGUs under section 112 if it determines that such regulation is appropriate and necessary, after considering the results of the Utility Study. As noted above, courts have interpreted the terms appropriate and necessary as conveying considerable discretion to the Agency in determining what is appropriate and necessary in a given context.

As explained more fully below, in this context, we interpret the statute to require the Agency to find it *appropriate* to regulate EGUs under CAA section 112 if the Agency determines that the emissions of one or more HAP emitted from EGUs pose an identified or potential hazard to public health or the environment at the time the finding is made. If the Agency finds that it is *appropriate* to regulate, it must find it *necessary* to regulate EGUs under section 112 if the identified or potential hazards to public health or the environment will not be adequately addressed by the imposition of the requirements of the CAA. Moreover, it

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[11] As explained above, the NAS Study studied the same issues Congress wanted addressed pursuant to section 112(n)(1)(C) and, because it was conducted five years after the NIEHS study, it was a more comprehensive study accounting for new information not available to NIEHS. Congress directed both studies and wanted EPA to consider the NAS Study before issuing the appropriate and necessary finding so we are reasonably focusing our discussion on the content of the later study.

may be *necessary* to regulate utilities under section 112 for a number of other reasons, including, for example, that section 112 standards will assure permanent reductions in EGU HAP emissions, which cannot be assured based on other requirements of the CAA.

The following subsections describe in detail our interpretation of the key statutory terms. We also explain below how the interpretations set forth in this notice are wholly consistent with the December 2000 Finding. Further, to the extent our interpretation differs from that set forth in the 2005 Action, we explain the basis for that difference and why the interpretation, as set forth in this preamble, is reasonable. *See National Cable & Telecommunications Ass'n, et al.* v. *Brand X Internet Services, et al.,* 545 U.S. 967, 981 (2005) (Discussing the deference provided to an Agency when changing interpretations the Court stated "change is not invalidating, since the whole point of *Chevron* deference is to leave the discretion provided by ambiguities of a statute with the implementing agency.") (Internal citations and quotations omitted); *see* also *Department of Treasury* v. *FLRA,* 494 U.S. 922, 933 (1990) (Finding that EPA's judgment should only be overturned if it is deemed unreasonable, not merely because other, reasonable alternatives exist).

a. "Appropriate" To Regulate EGUs

We interpret section 112(n)(1)(A) to require the Agency to find regulation of EGUs under section 112 appropriate if we determine that HAP emissions from EGUs pose a hazard to public health or the environment at the time the finding is made. The hazard to public health or the environment may be the result of HAP emissions from EGUs alone or the result of HAP emissions from EGUs in conjunction with HAP emissions from other sources. In addition, EPA must find that it is appropriate to regulate EGUs if it determines that any single HAP emitted by utilities poses a hazard to public health or the environment. We further interpret the term "appropriate" to not allow for the consideration of costs in assessing whether HAP emissions from EGUs pose a hazard to public health or the environment. Finally, we may conclude that it is appropriate, in part, to regulate EGUs if we determine that there are controls available to address HAP emissions from EGUs.

i. Basis for Interpretation

As stated above, the appropriate finding may be based on hazards to public health or the environment. Although we believe that Congress' primary concern, as expressed in section 112(n)(1)(A) and 112(n)(1)(C), related to hazards to public health, the inclusion of environmental effects in section 112(n)(1)(B) indicates Congress' interest in protecting the environment from HAP emissions from EGUs as well.

Moreover, the term "appropriate" is extremely broad and nothing in the statute suggests that the Agency should ignore adverse environmental effects in determining whether to regulate EGUs under section 112. Further, had Congress intended to prohibit EPA from considering adverse environmental effects in the "appropriate" finding, it would have stated so expressly. Absent clear direction to the contrary, and considering the purpose of the CAA (*see e.g.,* CAA section 101, 112(c)(9)(B)(ii)), it is reasonable to consider environmental effects in evaluating the hazards posed by HAP emitted from EGUs when assessing whether regulation of EGUs under section 112 is appropriate. Accordingly, we interpret the statute to authorize the Agency to base the appropriate finding on either hazards to public health or the environment.

We also maintain that the Agency should base its "appropriate" evaluation on the hazards to public health or the environment that exist at the time the determination is made, not after considering the imposition of the other requirements of the CAA. The Agency evaluates whether imposition of the requirements of the CAA will adequately address any identified hazards only in the context of the necessary finding. Thus, in assessing whether regulation of EGUs is appropriate under section 112, we evaluate the current hazards posed by such units, as opposed to projecting what such hazards may look like after imposition of the requirements of the CAA.

We further interpret the CAA as allowing the Agency to base the appropriate finding on hazards to public health or the environment that result from HAP emissions from EGUs alone or hazards to public health and the environment that result from HAP emissions from EGUs in conjunction with HAP emissions from other sources. Section 112(n)(1) does not focus exclusively on EGU-only HAP emissions.

As explained above, section 112(n)(1)(B) and (C) require either expressly or implicitly the consideration of Hg emissions from all sources, not just EGUs. Section 112(n)(1)(B) is of note because that provision does not require the Agency to determine the hazard posed by Hg from EGUs alone. Rather, Congress required EPA to evaluate the health and environmental effects of Hg emissions from "electric utility steam generating units, municipal waste combustion units, and other sources, including area sources." Section 112(n)(1)(C) is also relevant because it requires a human health-based assessment of the hazards posed by Hg without regard to the origin of the Hg. Congress could have directed an evaluation of the human health risk attributable to EGUs alone, but it did not. Congress also did not require such an assessment be conducted in the NAS Study.

In addition, Congress directed the Agency in section 112(n)(1)(A) to regulate EGUs under section 112 if the results of the Utility Study caused the Agency to conclude that regulation was appropriate and necessary. Section 112(n)(1)(A) is not written in a manner to preclude consideration of other information when determining whether it is appropriate and necessary to regulate EGUs under section 112, and that includes consideration of all hazards, both health and environmental, posed by HAP emitted by EGUs. *See United States* v. *United Technologies Corp.,* 985 F.2d 1148, 1158 (2d Cir. 1993) ("based upon" does not mean "solely").

Finally, focusing on HAP emissions from EGUs alone when making the appropriate finding ignores the manner in which public health and the environment are affected by air pollution. An individual that suffers adverse health effects as the result of the combined HAP emissions from EGUs and other sources is harmed, irrespective of whether HAP emissions from EGUs alone would cause that harm. For this reason, we believe we may consider the hazards to public health and the environment posed by HAP emissions from EGUs alone or in conjunction with HAP emissions from other sources.

Furthermore, the appropriate finding may be based on a finding that any single HAP emitted from EGUs poses a hazard to public health or the environment. Nothing in section 112(n)(1)(A) suggests that EPA must determine that every HAP emitted by EGUs poses a hazard to public health or the environment before EPA can find it appropriate to regulate EGUs under section 112. Interpreting the statute in this manner would preclude the Agency from addressing under section 112 identified or potential hazards to public health or the environment associated with HAP emissions from EGUs unless we found a hazard existed with respect to each and every HAP emitted.

Indeed, Congress' focus in section 112(n)(1)(B) and (C) on Hg indicates Congress' awareness that Hg was a problem and supports the position that EPA could find it appropriate to regulate EGUs based on the adverse health and environmental effects of a single HAP. Furthermore, the statute does not directly or expressly authorize the Agency to regulate only those HAP for which a hazard finding has been made. In fact, the statute requires the Agency to regulate EGUs under section 112 if the Agency finds regulation under section 112 is appropriate and necessary, and regulation under section 112 for major sources requires MACT standards for *all HAP* emitted from the source category. *See, e.g., National Lime Ass'n* v. *EPA,* 233 F.3d 625, 633 (DC Cir. 2000). For these reasons, we conclude we must find it appropriate to regulate EGUs under section 112 if we determine that the emissions of any single HAP from such units pose a hazard to public health or the environment.

We also maintain that the better reading of the term "appropriate" is that it does not allow for the consideration of costs in assessing whether hazards to public health or the environment are reasonably anticipated to occur based on EGU emissions. Had Congress intended to require the Agency to consider costs in assessing hazards to public health or the environment associated with EGU HAP emissions, it would have so stated.

This interpretation is consistent with the overall structure of the CAA. Congress did not authorize the consideration of costs in listing any source categories for regulation under section 112. In addition, Congress did not permit the consideration of costs in evaluating whether a source category could be delisted pursuant to the provisions of section 112(c)(9).

Under section 112(n)(1)(A), EPA is evaluating whether to regulate HAP emissions from EGUs at all. It is reasonable to conclude that costs may not be considered in determining whether to regulate EGUs under section 112 when hazards to public health and the environment are at issue.

Finally, consistent with sections 112(n)(1)(A) and 112(n)(1)(B), we conclude that we may base the appropriate finding on the availability of controls to address HAP emissions from EGUs.

ii. The December 2000 Finding

The Agency's interpretation of the term "appropriate," as set forth above, is wholly consistent with the Agency's appropriate finding in December 2000. As noted above, in 2000, we concluded that it was appropriate to regulate EGUs under section 112 because Hg in the environment posed a hazard to public health and the environment. The Agency also concluded it was appropriate because of uncertainties associated with the hazards posed by other HAP emitted from EGUs. 65 FR 79827. Finally, the EPA concluded that it was appropriate because of the availability of controls to reduce HAP emissions from EGUs. In making the finding as it related to Hg, the Agency considered the hazards posed by Hg in the environment and the contribution of EGUs to that hazard. In addition, EPA did not consider costs when making the appropriate determination. Further, the appropriate finding evaluated the hazards at the time, as opposed to the hazards remaining after imposition of the requirements of the CAA. EPA evaluated whether the other requirements of the CAA would adequately address the hazards in the necessary prong only.[12]

iii. The 2005 Action

As noted above, in 2005, EPA revised its December 2000 Finding and stated that the appropriate finding: (1) Could not be based on adverse environmental effects; (2) must be made considering only HAP emissions from EGUs; (3) must be made after consideration of the imposition of the requirements of the CAA; and (4) must consider other factors (*e.g.,* costs) even if we determine that HAP emissions from EGUs pose a hazard to public health. This proposal differs from the 2005 Action, and we address each of these differences below.

First, we change the position taken in 2005 that the appropriate finding could not be based on environmental effects alone. In 2005, we did not properly consider all of the provisions of section 112(n)(1). The Agency should not interpret the CAA to limit the Agency's discretion to protect the environment absent clear direction to that effect. In essence, the Agency's interpretation in 2005 would have required the Agency to ignore a catastrophic environmental harm (*e.g.,* the extinction of a species) if the Agency could not also identify a hazard to public health. EPA took this position regarding environmental effects in 2005 even though in that same rule it correctly interpreted section 112(n)(1)(A) to allow the Agency to consider information beyond the Utility Study in making the appropriate and necessary determination. 70 FR 15,997–99. The 2005 interpretation that EPA cannot consider environmental effects in evaluating whether it is appropriate to regulate EGUs under section 112 was neither reasonable nor consistent with the goals of the CAA, and, therefore, we are rejecting that interpretation and returning to the approach taken in 2000 that allowed consideration of environmental effects.

Second, for all of the reasons stated above, we are revisiting the 2005 interpretation that required the Agency to consider HAP emissions from EGUs without considering the cumulative impacts of all sources of HAP emissions. Nothing in section 112(n)(1)(A) prohibits consideration of HAP emissions from EGUs in conjunction with HAP emissions from other sources of HAP. We believe it is more reasonable to interpret the statute to authorize the Agency to consider the cumulative effects of HAP that are emitted from EGUs and other sources. This interpretation allows the Agency to evaluate more fully whether HAP emissions from EGUs pose a hazard to public health or the environment consistent with the manner in which the public and the environment are exposed to HAP emissions.

Third, we are revising the 2005 interpretation that required the Agency to evaluate the hazards to public health after imposition of the requirements of the CAA. We conclude today that in 2005 the Agency improperly conflated the appropriate finding and the necessary finding by requiring consideration of the ameliorative effects of other CAA requirements in both prongs of the appropriate and necessary finding. We believe the Agency must find it appropriate to regulate EGUs under section 112 if we determine that HAP emitted by EGUs pose a hazard to public health or the environment at the time the finding is made. The issue of how and whether those hazards are reduced after imposition of the requirements of the CAA is an issue for the necessary prong of the finding.

Finally, we are rejecting the 2005 interpretation that authorizes the Agency to consider other factors (*e.g.,* cost), even if the Agency determines that HAP emitted by EGUs pose a hazard to public health (or the environment). We reject the consideration of costs for all the reasons set forth above. Furthermore, the better reading of section 112(n)(1)(A) is that the Agency should find it appropriate to regulate EGUs under section 112 if a hazard to public health or the environment is identified. We think it

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[12] As explained below, EPA reasonably concluded in December 2000 that it was appropriate and necessary to regulate EGUs under section 112 based on the record before the Agency at that time.

unreasonable to decline to make the appropriate finding based on any factor, cost or otherwise, if we determine that EGUs pose a hazard to public health or the environment.

b. "Necessary" To Regulate EGUs

Once the Agency has determined that it is appropriate to regulate EGUs under section 112, the Agency must then determine whether it is necessary to regulate EGUs under section 112. As stated above, we have considerable discretion to determine whether regulation of EGUs under section 112 is necessary. The DC Circuit Court has stated that "there are many situations in which the use of the word 'necessary,' in context, means something that is done, regardless of whether it is indispensible, to achieve a particular end." *Cellular Telecommunication,* 330 F.3d at 510.

If the Agency concludes that it is appropriate to regulate EGUs, we believe it is necessary to regulate HAP emissions from EGUs if we determine that the imposition of the requirements of the CAA will not sufficiently address the identified hazards to public health or the environment posed by HAP that are emitted from EGUs. We maintain that we must find it necessary based on such a finding even if regulation under section 112 will not fully resolve the identified hazard to public health or the environment.

We may also determine it is necessary to regulate under section 112 if we are uncertain whether the imposition of the other requirements of the CAA will sufficiently address the identified hazards. We may find it necessary to regulate EGUs under section 112 even if we were to conclude, based on reasonable estimations of emissions reductions, that the imposition of the other requirements of the CAA would, or might, significantly reduce the identified hazard, because the only way to guarantee that such reductions will occur at all EGUs and be maintained is through a section 112(d) standard that directly regulates HAP emissions from utilities. Finally, we may also find it necessary to regulate EGUs under section 112 to further the policy goal of supporting international efforts to reduce HAP emissions, including Hg.

i. Necessary After Imposition of the Requirements of the CAA

In the Utility Study, Congress directed the Agency to evaluate the hazards to public health posed by HAP emissions from EGUs remaining after imposition of the requirements of the CAA, and it gave EPA 3 years to complete that Study. We interpret the necessary requirement first in the context of the phrase "after imposition of the requirements of [the CAA]." Section 112(n)(1)(A).

Congress did not define the phrase "after imposition of the requirements of the Act." The plain meaning of the term "requirement" is something that is necessary, or obligatory. *See, e.g.,* Random House Webster's Unabridged Dictionary, Deluxe Edition, 2001. Given that Congress intended the Utility Study to be completed by 1993, it is reasonable to interpret the phrase "after imposition of the requirements of the Act", as requiring the Agency to consider only those requirements that Congress directly imposed on EGUs through the CAA as amended in 1990 and for which EPA could reasonably predict HAP emission reductions at the time of the Utility Study. The most substantial requirement in this regard was the newly enacted ARP.

The purpose of the ARP was to reduce the adverse effects of acid deposition (more commonly known as "acid rain"), by limiting the allowable emissions of SO_2 and NO_X primarily from EGUs. In enacting the Acid Rain provisions of the Act, Congress explained that the problem of acid deposition was one of "national and international significance," that technologies to reduce the precursors to acid deposition were "economically feasible," and that "control measures to reduce precursor emissions from steam-electric generating units should be initiated without delay." CAA section 401(a). The ARP also includes a series of very specific emission reduction requirements. For example, the goals of the program include a reduction of annual SO_2 emissions by 10 million tons below 1980 levels and a reduction of NO_X emissions by two million tons from 1980 levels.

Moreover, the ARP achieved the required reductions by allocating allowances to emit SO_2 at reduced levels to each affected EGU. Sources were prohibited from emitting more SO_2 than the number of allowances held. To comply with these requirements, source owners or operators could elect to install controls, such as scrubbers, switch to lower sulfur fuels at their facilities, or purchase allowances from other EGUs that had reduced their emissions beyond what they were required by the ARP to achieve. It was known at the time of enactment of the 1990 Amendments that the controls used to reduce emissions of SO_2, primarily scrubbers, had the co-benefit of controlling HAP emissions, including Hg emissions. The ARP also included requirements for limiting NO_X emissions from EGUs. Considering the Acid Rain requirements under section 112(n)(1) is reasonable because the Act contained very specific emission reduction requirements for EGUs, and a tight compliance time-frame. In fact, all of the regulations implementing the SO_2 allowance trading portion of the ARP were completed by the mid-1990's.

The other significant requirement that Congress imposed in the 1990 Amendments was to revise the NSPS for NO_X emissions from EGUs by 1994. CAA 407(c). However, unlike the SO_2 allowance requirements of the ARP, Congress did not specify the amount of required reductions, but instead directed EPA to consider the improvements in methods for reducing NO_X when establishing standards for new sources. Thus, in the 1990 Amendments, Congress sought NO_X reductions from EGUs both through the ARP and a revision of the NSPS applicable to new sources. The Agency issued these NSPS in 1997.

There are other requirements of Title I of the Act that could affect EGUs, and they include the National Ambient Air Quality Standards (NAAQS). Congress did not impose these provisions directly on EGUs, however. Instead, EPA is responsible for developing the NAAQS, and states are primarily responsible for assuring attainment and maintenance of the NAAQS. For example, EPA stated in the Utility Study that implementation of the 1997 NAAQS for ozone and PM may lead to reductions in Hg emissions, but those potential reductions could not be sufficiently quantified because states have the ultimate responsibility for implementing the NAAQS. See Utility Study, pages ES–25, 1–3, 2–32, 3–14, and 6–15. States use a broad combination of measures (mobile and stationary) to obtain the reductions needed to meet the NAAQS. These decisions are unique to each state, as each state must identify and assess the sources contributing to nonattainment and determine how best to meet the NAAQS. EPA cannot predict with any certainty precisely how states will ensure that the reductions needed to meet the NAAQS will be realized. Moreover, there are additional uncertainties even were a state to impose requirements on EGUs through a State Implementation Plan (SIP), because each EGU may choose to meet the required reductions in a different manner, which could result in more or less HAP emission reductions. Accordingly, we do not believe it would have been appropriate to include such potential emissions reductions in determining whether it is necessary to regulate HAP emissions from EGUs under section 112.

Further, it is reasonable to interpret the phrase "after imposition of the requirements of the Act", as only requiring consideration of those requirements that Congress directly imposed on EGUs through the CAA as amended in 1990 and for which EPA could reasonably predict emission reductions at the time of the Utility Study. To interpret the phrase otherwise would require the Agency to look ahead two to three decades to forecast what possible requirements might be developed and applied to EGUs under some requirement of the CAA at some point in the future.

Indeed, such an interpretation would be inconsistent with the structure and purpose of section 112. As noted above, Congress gave EPA until 1993 to issue the Utility Study and expected the appropriate and necessary finding would follow shortly thereafter. Congress also required EPA to address HAP emissions rapidly from all source categories. See CAA 112(e), supra. It is reasonable to presume that Congress intended EPA to evaluate the need for EGU HAP controls in light of the requirements imposed upon the industry via the new 1990 requirements. Obviously the central requirement that was new and applied to EGUs was the ARP which would be implemented rapidly following passage of the 1990 amendments to the Act.

Although the above represents a reasonable interpretation of what Congress contemplated the Utility Study would examine with regard to "imposition of the requirements of the Act," we recognize that we have discretion to look beyond the Utility Study in determining whether it is necessary to regulate EGUs under section 112. Given that several years have passed since the December 2000 Finding, we conducted additional analysis. Although not required, we conducted this analysis to demonstrate that even considering a broad array of diverse requirements, it remains appropriate and necessary to regulate EGUs under section 112.

Specifically, we examined a host of requirements, which in our view, far surpass anything Congress could have contemplated in 1990 we would consider as part of our "necessary" determination. For example, our analysis includes certain state rules regulating criteria pollutants, Federal consent decrees, and settlement agreements for criteria pollutants resolving state-initiated and citizen-initiated enforcement actions.[13] We did not include in our analysis any state-only HAP requirements or voluntary actions to reduce HAP emissions, as those are not requirements of the CAA, and are not required by Federal law to remain applicable.[14]

ii. Necessary Interpretation

If we determine that the imposition of the requirements of the CAA will not address the identified hazards, EPA must find it necessary to regulate EGUs under section 112. Section 112 is the authority Congress provided to address hazards to public health and the environment posed by HAP emissions and section 112(n)(1)(A) requires the Agency to regulate under section 112 if we find regulation is "appropriate and necessary." If we conclude that HAP emissions from EGUs pose a hazard today, such that it is appropriate, and we further conclude based on our scientific and technical expertise that the identified hazards will not be resolved through imposition of the requirements of the CAA, we believe there is no justification in the statute to conclude that it is not necessary to regulate EGUs under section 112.

Furthermore, we believe it is necessary to regulate if we have identified a hazard to public health or the environment that will not be addressed by imposition of the requirements of the CAA even if regulation of EGUs under section 112 will not fully resolve the identified hazard. We conclude that this is particularly true for bio-accumulative HAP such as Hg because EPA can only address such emissions from domestic sources and mitigation of identified risks associated with such HAP is a reasonable goal. *See* section 112(c)(6). EPA cannot decline to find it "necessary" to regulate EGUs under section 112 when it has identified a hazard to public health or the environment, simply because that regulation will not wholly resolve the identified hazards. The statute does not require the Agency to conclude that identified hazards will be fully resolved before it may find regulation under section 112 necessary. *See Massachusetts* v. *EPA,* 549 U.S. 497, 525 (2007).

In addition, we may determine it is necessary to regulate under section 112 even if we are uncertain whether the imposition of the requirements of the CAA will address the identified hazards. Congress left it to EPA to determine whether regulation of EGUs under section 112 is necessary. We believe it is reasonable to err on the side of regulation of such highly toxic pollutants in the face of uncertainty. Further, if we are unsure whether the other requirements of the CAA will address an identified hazard, it is reasonable to exercise our discretion in a manner that assures adequate protection of public health and the environment. Moreover, we must be particularly mindful of CAA regulations we include in our modeled estimates of future emissions if they are not final or are still subject to judicial review (*i.e.,* the Transport Rule[15]). If such rules are either not finalized or upheld by the Courts, the level of risk would potentially increase.

We also may find it necessary to regulate EGUs under section 112 even if we conclude, based on reasonable estimations of emissions reductions, that the imposition of the other requirements of the CAA will significantly reduce the identified hazard. We maintain this is reasonable because the only way to guarantee that the necessary reductions in HAP emissions will occur at all EGUs and be maintained is through a section 112(d) standard that directly regulates HAP emissions from EGUs. This is true because sources could discontinue use of controls for criteria pollutants that achieve HAP reductions as a co-benefit if new control technologies or practices are identified that reduce the relevant criteria pollutants but do not also reduce HAP. For example, scrubbers are often used to reduce SO_2 emissions and those scrubbers also reduce emissions of several HAP. However, if an EGU with a scrubber started complying with its SO_2 standard by switching to low sulfur coal or purchasing allowances, the HAP

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[13] In our analysis, we included state requirements and citizen and state settlements associated with criteria pollutants because those requirements may have a basis under the CAA. We did not, however, conduct an analysis to determine whether that was the case in each instance. As such, we believe there may be instances where we should not have considered certain state rules or state and citizen suit settlements in our analysis, because those requirements are based solely in state law and are not required by Federal law.

[14] Although, as explained below, our technical analysis examined impacts projected out to 2016, this is a very conservative approach. Given that two decades have passed since the enactment of the 1990 CAA Amendments, we believe we can find it appropriate and necessary to regulate EGUs under section 112, if we determine EGU HAP emissions pose a hazard to public health and the environment today without considering future HAP emission reductions. Congress could not have contemplated in 1990 that EPA would have failed in 2011 to have regulated HAP emissions from EGUs where hazards to public health and the environment remain.

[15] Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone. Proposed Rule. August 2, 2010. 75 FR 45,210.

emission reduction co-benefits associated with the scrubber would no longer be realized. In addition, at the time Congress passed the 1990 CAA amendments, there were many older EGUs that had few or no controls in place. Over 20 years later, there remain a significant number of older EGUs that are only minimally controlled. The Agency may find it necessary to regulate EGUs under section 112 to ensure that these minimally controlled EGUs and those units that switch to other criteria pollutant compliance options, thereby no longer achieving the same HAP reductions, are subject to HAP regulation, such that the estimated reductions in the identified hazards are realized.

iii. December 2000 Finding

Our interpretation of the necessary finding is reasonable and consistent with the December 2000 Finding. In that finding, EPA determined that the imposition of the requirements of the CAA would not address the serious public health and environmental hazards resulting from EGU HAP emissions. We also stated that section 112 is the authority to address hazards from HAP emissions. Because we determined that the imposition of the requirements of the CAA would not address the identified hazards, we correctly concluded it was necessary to regulate under section 112. Although the Agency did not expressly interpret the term necessary in the December 2000 Finding, under the interpretation set forth above, the Agency must find it necessary if we conclude that the imposition of the other requirements of the CAA will not address the identified hazards. Because EPA reached that conclusion, the Agency correctly determined that it was necessary to regulate EGU HAP emissions and did not need to base the 2000 necessary finding on any of the other bases set forth above.

iv. The 2005 Action

We stated in 2005 that “it is necessary to regulate EGUs under section 112 only if there are no other authorities under the CAA that, if implemented, would effectively address the remaining HAP emissions from EGUs.” 70 FR 16,001.[16] In essence, we stated in 2005 that section 112(n)(1)(A) requires the Agency to scour the CAA to determine whether there is a direct or indirect manner in which EPA could regulate HAP emissions from EGUs, notwithstanding the fact that Congress expressly provided section 112 for the purpose of regulating HAP emissions from stationary sources. This interpretation is not reasonable.

Congress enacted section 112 for the express purpose of regulating HAP emissions. It is not reasonable to interpret section 112(n)(1)(A) to require the Agency to find another provision of the CAA to address identified hazards to public health or the environment. This is particularly the case where the Agency would not have certainty that such alternative legal theory would withstand judicial scrutiny because section 112 is the authority expressly provided to regulate HAP emissions and no other provision provides express authority to regulate HAP emissions from existing stationary sources.[17] Although anyone can challenge the substance of a section 112 standard, no one can challenge that regulation of HAP emissions under section 112 is proper for validly listed source categories.

Furthermore, section 112(n)(1)(A) states explicitly that the Agency shall regulate EGUs “under this section” if the Agency determines it is “appropriate and necessary after considering the results of the (Utility Study).” We reiterate that the only precondition to regulating EGUs is consideration of the results of the Utility Study. We believe it is unreasonable to argue that Congress directed the Agency as part of the Utility Study to scour the CAA for alternative legal authorities for regulating HAP emissions, either directly or indirectly. Indeed, the Agency did not interpret the requirement in section 112(n)(1)(A) to conduct the study in that manner, as evidenced by the Utility Study itself. Absent that interpretation, we think it is unreasonable to conclude that the Agency must undertake such an effort to make the necessary finding because Congress authorized the Agency to base the “appropriate and necessary” finding on the Utility Study alone.

For all the reasons above, we believe it is appropriate to regulate EGUs under section 112 if the Agency determines that HAP emissions from such units pose a hazard to public health or the environment at the time of the finding, and it is necessary to regulate EGUs under section 112 if the imposition of the other requirements of the CAA will not adequately address the identified hazards to public health or the environment, or there are other compelling reasons making it necessary to regulate HAP emissions from EGUs under section 112.

c. Hazards to Public Health or the Environment

Section 112(n)(1)(A) neither defines the phrase “hazards to public health,” nor sets forth parameters for EPA to use in determining whether HAP emissions from EGUs pose a hazard to public health. The phrase is also not defined elsewhere in the CAA. EPA, therefore, has broad discretion, using its technical and scientific expertise, to determine whether HAP emissions from EGUs pose a hazard to public health.

In evaluating hazards to the environment, however, Congress did provide some direction. Specifically, it defined the term “adverse environmental effects” in section 112(a)(7), and as explained further below, we evaluate hazards to the environment consistent with that definition.

Because Congress did not define “hazard to public health” the Agency must use its scientific and technical expertise to determine what constitutes a hazard to public health in the context of EGU HAP emissions. The Agency considers various factors in evaluating hazards to public health, including, but not limited to, the nature and severity of the health effects associated with exposure to HAP emissions; the degree of confidence in our knowledge of those health effects; the size and characteristics of the populations affected by exposures to HAP emissions; the magnitude and breadth of the exposures and risks posed by HAP emissions from a particular source category, including how those exposures contribute to risk in populations with additional exposures to HAP from other sources; and the proportion of the population exposed above benchmark levels of concern (*e.g.,* cancer risks greater than 1 in a million or non-cancer effects with a hazard quotient (HQ) greater than 1). See Section III(D) below for a discussion of the Agency’s technical conclusions as to whether a hazard to public health or the environment exists based on the facts at issue here.

Although Congress provided no definition of hazard to public health, section 112(c)(9)(B) is instructive. In that section, Congress set forth a test for removing source categories from the section 112(c) source category list. That

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[16] In the rule reconsidering the 2005 Action, we further clarified that in evaluating the effectiveness of other CAA authorities we considered whether those other authorities could be implemented in a cost-effective and administratively effective manner. 71 FR 33,391. We need not address this in detail because we conclude that the threshold conclusion that the Agency must look for alternative CAA authorities that could be used to regulate HAP emissions from EGUs before finding it necessary is invalid.

[17] In theory, an NSPS is legally permissible for new stationary sources of HAP.

test is relevant because it reflects Congress' view as to the level of health effects associated with HAP emissions that Congress thought warranted continued regulation under section 112. The Agency finds section 112(c)(9)(B)(i) particularly instructive because it provides a numerical threshold for HAP that may cause cancer. Specifically, that provision provides that EPA may delete a source category from the section 112(c) list if no source in the category emits such HAP in quantities which may cause a lifetime risk of cancer *greater than one in one million* to the individual in the population who is most exposed to such HAP emissions. Thus, the Agency reads section 112(c)(9)(B)(i) to reflect Congress' view of the acceptable hazard to public health for HAP that may cause cancer.

Congress defined the phrase "adverse environmental effect" in section 112(a)(7) to mean "any significant and widespread adverse effect, which may reasonably be anticipated, to wildlife, aquatic life, or other natural resources, including adverse impacts on populations of endangered or threatened species or significant degradation of environmental quality over broad areas."

Section 112(n)(1)(B) required EPA to examine the environmental effects of Hg emissions. Because Congress defined the term "adverse environmental effect" in section 112(a)(7), we believe that such definition should guide our assessment of whether hazards to the environment posed by Utility HAP emissions exist. As with hazards to public health, however, the Agency must use its discretion to determine whether the adverse environmental effects identified warrant a finding that it is appropriate to regulate HAP emissions from EGUs based on those effects. In evaluating the environmental effects, we have stated that we may consider various aspects of pollutant exposure, including: "[t]oxicity effects from acute and chronic exposures" expected from the source category (as measured or modeled); "persistence in the environment;" "local and long-range transport;" and "tendency for bio-magnification with toxic effects manifest at higher trophic levels." 67 FR 44,718 (July 3, 2002).

In interpreting the term itself, we believe the broad language in section 112(a)(7) referring to "any" enumerated effect "which may be reasonably anticipated" evinces Congressional intent to not restrict the scope of that term to only certain specific impacts. 62 FR 36440 (July 7, 1997); 63 FR 14094 (March 24, 1998). Further, the section 112(a)(7) reference to "any" enumerated effect in the singular clearly contemplates impacts of limited geographic scope, suggesting that the "widespread" criterion does not present a particularly difficult threshold to cross. *Id.* This is further supported by the fact that section 112(a)(7) provides as an example of adverse environmental effects, adverse impacts on populations of endangered or threatened species, which as reflective of their imperiled status are especially likely to exist in limited geographic areas. EPA believes that the "widespread" criterion would not exclude impacts that might occur in only one region of the country. *Id.*

d. Regulating EGUs "Under This Section"

The statute directs the Agency to regulate EGUs under section 112 if the Agency finds such regulation is appropriate and necessary. Once the appropriate and necessary finding is made, EGUs are subject to section 112 in the same manner as other sources of HAP emissions. Section 112(n)(1)(A) provision provides, in part, that:

> [t]he 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) of this section* after imposition of the requirements of this chapter * * * 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.*

Emphasis added.

In the first sentence, Congress described the study and directed the Agency to evaluate the hazards to public health posed by HAP emissions listed *under subsection* (b) (*i.e.,* section 112(b)). The last sentence requires the Agency to regulate under this section (*i.e.,* section 112) if the Agency finds such regulation is appropriate and necessary after considering the results of the study required by *this subparagraph* (*i.e.,* section 112(n)(1)(A)). The use of the terms section, subsection, and subparagraph demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs if the Agency finds it appropriate and necessary to do so. Congress directed the Agency to regulate utilities "under this section," and accordingly EGUs should be regulated in the same manner as other categories for which the statute requires regulation.

Furthermore, the DC Circuit Court has already held that section 112(n)(1) "governs how the Administrator decides whether to list EGUs" and that once listed, EGUs are subject to the requirements of section 112. *New Jersey,* 517 F.3d at 583. Indeed, the DC Circuit Court expressly noted that "where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly," noting that "section 112(c)(6) expressly exempts EGUs from the strict deadlines imposed on other sources of certain pollutants." *Id.* Congress did not exempt EGUs from the other requirements of section 112, and once listed, EPA is required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d), as described above.

EPA requests comment on section III.A.

B. The December 2000 Appropriate and Necessary Finding was Reasonable

EPA reasonably determined in December 2000 that it was appropriate and necessary to regulate HAP emissions from EGUs under CAA section 112. In making that finding, EPA considered all of the information that Congress had identified as most salient, including the Utility Study, the Mercury Study, and the information in the NAS Study.[18] EPA even conducted an ICR soliciting emissions information on Hg, which was the HAP of most concern to Congress, as evidenced by section 112(n)(1). EPA collaborated further with a number of other entities and Federal Agencies, including the U.S. Department of Energy (DOE). EPA carefully evaluated all of this information, much of which had been the subject of extensive peer review, and reasonably determined, on the record before the Agency at the time, that it was appropriate and necessary to regulate EGUs under section 112.

1. EPA Appropriately Based the Finding on the Information Required by Section 112(n)(1) and Reasonably Made the Finding Once It Had Completed the Required Studies

In making the appropriate and necessary finding in 2000, EPA considered all of the relevant information in the three Studies required by section 112(n)(1) and the NAS Study. 65 FR 79826–27. The Utility, Mercury, and NAS Studies together consisted of thousands of pages of information and technical analyses. All of these studies were peer reviewed prior to issuance. In fact, the Mercury Study was reviewed by over 65

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[18] As explained above, we discuss the NAS Study here because it addressed the same issues as the NIEHS study, and it is the more recent study.

independent scientists.[19] The NAS Study contains a thorough technical discussion summarizing the state of the science at the time regarding the human health effects of MeHg.

In addition to conducting the studies that Congress required, EPA collected relevant information on Hg emissions and available control technologies. Specifically, pursuant to a CAA section 114 ICR, EPA collected data on the Hg content in coal from all coal-fired EGUs for calendar year 1999. Through the 1999 ICR, EPA also obtained stack test data for certain coal-fired EGUs to verify Hg emissions estimates for the EGU source category. 65 FR 79826. EPA further solicited data from the public through a February 29, 2000, notice (65 FR 10,783), and provided the public an opportunity to provide its views on what the regulatory finding should be at a public meeting. 65 FR 79826 (citing 65 FR 18992). Finally, EPA undertook an evaluation of the Hg control performance of various emission control technologies that were either currently in use on EGUs or that could be applied to such units for Hg control. EPA conducted this evaluation with other parties, including the DOE. 65 FR 79826. EPA also evaluated other emission control approaches that would reduce EGU HAP emissions. *Id.* at 79827–29.

Although Congress did not provide a deadline by which EPA must issue the appropriate and necessary finding, the deadlines Congress provided for completion of the required studies signal that Congress wanted EPA to make the appropriate and necessary finding shortly after completion of the studies. Congress required that the Utility Study and NIEHS Study be submitted by November 15, 1993, and the Mercury Study by November 15, 1994. We reasonably conclude based on the timing of the studies that Congress wanted the Agency to evaluate the hazards to public health and the environment associated with HAP emissions from EGUs as quickly as possible and take steps to regulate such units under section 112 if hazards were identified.

Congress later provided a direct signal as to the timing of the appropriate and necessary finding in the committee report associated with EPA's fiscal year 1999 appropriations bill, which directed the Agency to fund the NAS Study. In that report, Congress indicated that it did not want the Agency to make the appropriate and necessary finding for Hg until the NAS study was completed. *See* H.R. Conf. Rep. No 105–769, at 281–282 (1998).[20]

After considering all of the information that Congress considered most relevant, including the NAS Study that was issued in June 2000, EPA determined that it was appropriate and necessary to regulate EGUs under section 112 and listed such units for regulation on December 20, 2000. As explained below, the Agency acted reasonably in issuing the finding at that time because of the identified and potential hazards to public health and the environment associated with HAP emissions from utilities, which the Agency concluded would not be addressed through imposition of the requirements of the CAA. It would not have been reasonable to delay the finding to collect additional information given the considerable delay in completion of the required studies and the hazards to public health and the environment identified as of December 2000.

2. EPA Reasonably Concluded in December 2000 That It Was Appropriate To Regulate EGUs Under Section 112

The December 2000 Finding that it was appropriate to regulate EGUs under section 112 focused largely on hazards to public health and the environment associated with Hg emissions. EPA reasonably focused on this pollutant given that Hg is a persistent, bioaccumulative pollutant that causes serious neurotoxic effects. Indeed, Congress specifically identified this pollutant as one of concern and required two separate studies to be conducted regarding Hg emissions. *See* Section 112(n)(1)(B) and (C). The information before the Agency in 2000 concerning Hg was both well-documented and scientifically supported. Based on all of the information before it, the Agency concluded that Hg emissions from EGUs posed a hazard to public health. It was also reasonable for the Agency to find regulation of EGUs appropriate given the uncertainties regarding the extent of public health impacts posed by non-Hg HAP. Finally, it was reasonable to base the appropriate finding on the availability of controls for HAP emissions from EGUs.

a. The Agency Reasonably Concluded It Was Appropriate To Regulate EGUs Based on Hg Emissions

By 2000, the Agency had amassed "a truly vast amount of data" on Hg. *See* October 10, 1997, letter (page 2) submitting Science Advisory Board (SAB) peer review recommendations on draft Mercury Study.[21] Those data confirmed the hazards to public health and the environment associated with Hg. The data also helped EPA identify the populations of most concern with regard to MeHg exposure. *See* CAA 112(n)(1)(C). Finally, the data showed that EGUs were the largest unregulated source of Hg emissions in the U.S., and that EGUs were projected to increase their Hg emissions to approximately 60 tons in 2010.

We discuss below the central pieces of data and information concerning Hg that formed the basis of our conclusion that Hg posed a threat to public health and the environment.[22] These conclusions were largely drawn from the Mercury Study, which, as noted above, was reviewed by over 65 peer reviewers. Upon reviewing the draft report, the SAB noted that the "major findings of the draft report are well supported by the scientific evidence." In direct response to the SAB review, the Agency conducted additional, comprehensive analyses addressing SAB's recommendations. Thus, in 2000, the Agency had before it a comprehensive record concerning Hg emissions, including the best available science on Hg at the time.

i. Key Facts: Impacts of Hg on Health and the Environment

EPA first concluded that Hg from EGUs was the HAP of greatest concern. *Id.* at 79827. The Agency explained that "mercury is highly toxic, persistent, and bioaccumulates in food chains;" that Hg deposited on land and water can then be metabolized by microorganisms into MeHg; that MeHg is "a highly toxic, more bioavailable, form that biomagnifies in the aquatic food chain (*e.g.,* fish);" and that nearly all of the Hg in fish is MeHg. 65 FR 79827. The Agency further noted that fish consumption is the primary route of exposure for humans and wildlife, and, by July 2000, 40 states and America Samoa had issued fish advisories for Hg,

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[19] Mercury Study Report to Congress, Vol. I, Pg. 6, December 1997.

[20] This direction is consistent with section 112(n)(1). As noted above, the Utility Study was the only condition precedent to making the appropriate and necessary finding. The NIEHS study called for by 112(n)(1)(C) was to have been completed at the same time as the Utility Study. As such, Congress had originally contemplated that both the Utility and NIEHS studies would be available at the time the Agency made the appropriate and necessary finding. The NAS study considered the same information required in the NIEHS study so the Congressional direction in the fiscal year 1999 appropriation is consistent with the original drafting of section 112(n)(1).

[21] *http://yosemite.epa.gov/sab/SABPRODUCT.nsf/FF2962529C7B158A852571AE00648B72/$File/ehc9801.pdf.*

[22] The central conclusions underlying the 2000 finding are described in detail in the 2000 notice, at 65 FR 79829–30.

with 13 of those states issuing advisories for all the water bodies in their state. 65 FR 79827. Finally, the Agency explained that neurotoxicity is the health effect of greatest concern with MeHg exposure, and that exposures to MeHg can have serious toxicological effects on wildlife as well as humans.

EPA recognized that increased Hg deposition would lead to increased levels of MeHg in fish and such "increased levels in fish [would] * * * lead to toxicity in fish-eating birds and mammals, including humans." 65 FR 79830. EPA agreed with the NAS that "the long term goal needs to be the reduction in the concentrations of methylmercury in fish" and concluded that reducing Hg emissions from EGUs was "an important step toward achieving that goal." 65 FR 79830.

The Agency then identified the most affected populations. Specifically, the Agency concluded that women of childbearing age are the population of greatest concern because the developing fetus is the most sensitive to the effects of MeHg. 65 FR 79827. EPA estimated that at that time, 7 percent of women of childbearing age (or about 4,000,000 women) in the continental U.S. were exposed to MeHg at levels that exceeded the RfD and that about 1 percent of women of childbearing age (or about 580,000 women) had MeHg exposures 3 to 4 times the RfD. 65 FR 79827.

The NAS Study affirmed EPA's assessment of the toxicity of MeHg and that the RfD EPA had developed for MeHg was valid. 65 FR 79827. The Agency acknowledged that there was uncertainty with risk at exposure above the RfD, but indicated that risk increased with increased exposure. 65 FR 79827. In addition to focusing on women of childbearing age and developing fetuses, EPA stated a particular concern for subsistence fish-eating populations due to their regular and frequent consumption of relatively large quantities of fish. 65 FR 79830.

As for environmental effects, the Agency observed adverse effects to avian species and wildlife in laboratory studies at levels corresponding to fish tissue MeHg concentrations that are exceeded by a significant percentage of fish sampled in lake surveys. 65 FR 79830. The Agency explained that wildlife consume fish from a more localized geographic area than humans, which can result in elevated levels of Hg in certain fish eating species. Those species include, for example, the kingfisher and some endangered species, such as the Florida panther. 65 FR 79830.

In summary, in the December 2000 Finding, EPA identified Hg in the environment as a hazard to public health and the environment, determined that a significant segment of the most sensitive members of the population were exposed to MeHg at levels exceeding the RfD, and confirmed that the RfD was valid.

ii. EGU Emissions of Hg

In the 2000 finding, the Agency estimated that about 60 percent of the total Hg deposited in the U.S. came from U.S. anthropogenic air emission sources. 65 FR 79827. The Agency stated that the remainder of the Hg deposited in the U.S. was from natural emission sources, reemissions of historic global anthropogenic Hg releases, and non-domestic anthropogenic sources of Hg. 65 FR 79827. EPA identified coal combustion and waste incineration as the source categories likely to bear the greatest responsibility for direct anthropogenic Hg deposition in the continental U.S. 65 FR 79827. EPA further explained that EGUs are the largest unregulated domestic source of Hg emissions, accounting for approximately 30 percent of the current anthropogenic air emissions from domestic sources. 65 FR 79827. These numbers, taken together, reveal that EGUs accounted for approximately 18 percent of the total Hg deposition in the U.S on an annual basis, considering all U.S. anthropogenic sources, natural emission sources, reemissions of historic global anthropogenic Hg releases, and non-domestic anthropogenic sources of Hg.[23]

In 2000, the Agency also found a plausible link between domestic anthropogenic Hg emissions and MeHg in fish. 65 FR 79829. The Agency explained that although that link could not be estimated quantitatively at the time, the facts before the Agency were sufficient for it to conclude that EGU Hg emissions posed a hazard to public health. *Id.* at 79830. Those facts included, for example, the link between coal consumption and Hg emissions, EGUs being the largest domestic source of Hg, and certain segments of the population being at risk for adverse health effects due to consumption of contaminated fish. *Id.*

iii. EPA's Conclusions Regarding Hg

Based on the foregoing and all of the information set forth in the December 20, 2000, notice, the Agency found that Hg emissions from EGUs posed a hazard to public health and the environment. In making this finding, the Agency focused on the significant adverse health effects associated with MeHg and the persons most adversely impacted by Hg. The populations most affected were women of childbearing years and their developing fetuses and subsistence fishers. The Agency viewed the adverse health effects and environmental effects described above in conjunction with the then current Hg emissions information provided by EGUs in response to the 1999 ICR. Based on that information, EPA concluded that EGUs accounted for approximately 30 percent of the U.S. anthropogenic emissions of Hg, which translated into about 18 percent of the total Hg deposition in the U.S. at that time. EPA also knew that Hg from EGUs comprised an undetermined amount of the reemissions of Hg. *See* Mercury Study, Volume 3, page 2–3.

At the time of the December 2000 Finding, the Agency had issued section 112 or 129 standards for several of the other source categories that were significant Hg emitters, and the Agency was required by the CAA to establish section 112 or 129 standards for the other significant Hg emitters. *See* Standards for Large Municipal Waste Combustors, 40 CFR part 60, subpart Ea (NSPS), 56 FR 5507 (February 11, 1991), as amended, and 40 CFR part 60, subpart Eb (Emissions Guidelines), 60 FR 65419 (December 19, 1995), as amended; Standards for Medical Waste Incinerators, 40 CFR part 60, subpart Ec (NSPS), 62 FR 48382 (September 15, 1997), as amended, and 40 CFR part 60, subpart Ce (Emission Guidelines), 62 FR 48379 (September 15, 1997); Standards for Hazardous Waste Combustors, 40 CFR part 63, subpart EEE, 64 FR 53038 (September 30, 1999); Standards for Small Municipal Waste Combustors, 40 CFR part 60, subpart AAAA (NSPS), 65 FR 76355 (December 6, 2000), and 40 CFR part 60, subpart BBBB (Emissions Guidelines), 65 FR 76384 (December 6, 2000); and standard for Portland cement manufacturers (40 CFR part 63, subpart LLL, 64 FR 31925 (June 14, 1999)).[24] Most of these categories emitted far less Hg than EGUs at the time of the finding. Thus, at the time EPA made the December 2000 Finding, the record

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[23] EPA estimated that U.S. anthropogenic air emissions of mercury accounted for 60 percent of total deposition in the U.S. and U.S. EGUs accounted for 30 percent of that deposited mercury. Thirty percent of the 60 percent contribution is equal to approximately 18 percent of the total deposition. See Utility Study, page 7–28.

[24] The NESHAP for Portland cement did not include a standard for Hg when initially promulgated. In *National Lime Ass'n* v. *EPA,* the DC Circuit Court held that section 112(d) contains a clear statutory directive to regulate all HAP emitted from a listed source category. 233 F.3d 624, 634 (DC Cir. 2000). EPA recently issued final section 112 standards for Portland cement manufacturers, including a standard for Hg emissions from such sources.

reflected that Hg posed hazards to public health and the environment, that EGUs were the single largest unregulated domestic source of Hg emissions, and that HAP emissions from EGUs would remain unregulated absent listing under section 112. EPA reasonably found at the time that reducing Hg emissions from EGUs would further the goal of mitigating the hazards to public health and the environment posed by Hg.

EPA also reasonably predicted that incremental reductions in Hg emissions, including from EGUs, would lead to incremental reductions in the MeHg concentration in fish tissue, and that such reductions would, in turn, reduce the risk to public health and the environment. 65 FR 79830. The Mercury Study recognized that Hg is a metal that remains in the environment permanently and can circulate continuously through various environmental media. Although EPA was aware that reductions of Hg from anthropogenic sources may not lead to immediate reductions in fish tissue levels, such reductions would nonetheless serve the long-term goal of reducing the mobilization of Hg to the atmosphere and thus reduce MeHg concentrations in fish.

EPA, therefore, reasonably determined based on the facts that existed at the time that regulation of EGUs was appropriate in order to reduce the hazards to public health and the environment associated with the Hg emissions from EGUs. EPA expressly acknowledged that there were uncertainties concerning the extent of the risk due to Hg emissions from EGUs, because the Agency had not quantified the amount of MeHg in fish that was directly attributable to EGUs compared to other sources of MeHg. 65 FR 79827. That EPA did not quantify in 2000 the amount of MeHg in fish due to EGUs did not preclude EPA from making an "appropriate" finding. Nowhere in section 112(n)(1) or in its direction concerning the NAS Study did Congress require EPA to quantify the amount of MeHg in fish tissue that was directly attributable to EGUs.[25] Moreover, EPA did not have sufficient confidence in its modeling tools at the time to draw conclusions about the contribution of specific source types to fish MeHg concentrations in specific geographic areas or nationally. These uncertainties are well described in the Utility, Mercury, and NAS Studies.

In any event, in light of the breadth of the scientific evidence before the Agency and the conclusions the Agency reached, it would not have been reasonable to delay the finding to develop an analytical tool to apportion the Hg in fish. The Hg problem at the time was well documented, and the fact that EGUs represented such a significant portion of the Hg deposition in the U.S. was ample evidence that it was appropriate to regulate emissions from EGUs—the single largest unregulated domestic source of Hg emissions. 65 FR 79827.

Finally, the Agency had already delayed in completing the section 112(n)(1) studies. Additional delay would have been unreasonable because of the persistence of Hg in the environment and its tendency to bioaccumulate up the food chain, both aspects of Hg in the environment that make it critical to limit additional releases to the environment as quickly as possible. In addition, delay would have been unreasonable because EPA estimated at that time that about 7 percent of women of child-bearing age, one of the most at-risk populations, was exposed to Hg at levels exceeding the RfD, and EPA knew that as the level of exposure above the RfD increased, the level of risk and the extent and severity of adverse effects increased. Thus, EPA reasonably made the appropriate and necessary determination in 2000 to ensure that the largest unregulated domestic source of Hg would be required to install controls, thereby achieving an incremental reduction in the risk associated with a persistent, bioaccumulative HAP.

b. The Appropriate Finding for Non-Hg HAP Was Reasonable

The December 2000 Finding was also reasonable as it pertained to the non-Hg HAP emitted from EGUs. The Agency found it was appropriate to regulate EGUs based on the potential human health concerns from non-Hg HAP, particularly Ni from oil-fired EGUs, and the uncertainties regarding the public health impact of emissions of such HAP. 65 FR 79830. Based on the information in the Utility Study, EPA could not conclude based on the available information that the non-Hg HAP posed no hazards to public health.

Specifically, the Agency noted that several non-Hg HAP metals, including As, Cr, Ni, and Cd, were of potential concern for carcinogenic effects. 65 FR 79827. EPA acknowledged that the risks did not appear high, but it stated that the risks were not sufficiently low to disregard the metals as a potential concern for public health. 65 FR 79827; *see* Utility Study, Table 5–4, page 5–9 (finding cancer risks from oil-fired EGUs alone for Ni exceeded 1 in a million). The Agency also indicated that dioxins, HCl, and HF were of potential concern and might be evaluated further. 65 FR 79827.

EPA did not view the risks associated with non-Hg HAP in a vacuum. Rather, EPA considered the threat to public health, including uncertainties, associated with both Hg and non-Hg HAP emissions from EGUs in determining whether it was appropriate to regulate such units under section 112.

Finally, even looking solely at non-Hg HAP, EPA's conclusions support regulation of EGUs under section 112. Although Congress provided no metric for the hazard to public health determination, section 112(c)(9) is instructive. Specifically, in that section, Congress set forth a test for removing source categories from the section 112(c) source category list. That test is relevant because it reflects Congress' view as to the level of health effects associated with HAP emissions that Congress thought warranted regulation under section 112. If a source category failed to meet that test, it would remain subject to the requirements of CAA section 112. Thus, CAA section 112(c)(9) can be read to reflect Congress' view of what adverse public health effects from HAP emissions are acceptable and thus do not warrant regulation under CAA section 112.

For carcinogens, which are at issue here, section 112(c)(9)(B)(i) provides that EPA may delete a source category from the section 112(c) list if no source in the category (or group of sources in the case of area sources) emits such HAP in quantities that may cause a lifetime risk of cancer greater than one in one million to the individual in the population who is most exposed to emissions of such pollutants from the source (or group of sources in the case of area sources). Thus, section 112(c)(9)(B)(i) prohibits the Agency from delisting a major source category from the section 112(c) list if any single source within that category emits cancer causing HAP at levels that may cause a

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[25] Consistent with section 112(n)(1), none of the studies addressed the amount of MeHg in fish attributable solely to EGUs. Instead, in the Utility and Mercury Studies, EPA discussed the significant contribution EGUs made to Hg deposition and that Hg deposition was problematic from a health and environmental standpoint. EPA submitted both the Utility Study and the Mercury Study to Congress by 1998. Aware of these studies, Congress, when directing the additional NAS Study, still did not require EPA to determine the amount of MeHg in fish due solely to EGUs. In light of this fact and the broad discretion Congress gave EPA to determine whether it was appropriate or necessary to regulate EGUs under section 112, EPA acted reasonably in 2000 by not delaying its finding several years to conduct an analysis of the portion of MeHg in fish due solely to EGUs.

lifetime cancer risk greater than one in one million to the most exposed individual. The Utility Study demonstrated that there were EGUs whose emissions resulted in a cancer risk greater than one in one million. Accordingly, it was reasonable to conclude at the time that non-Hg HAP emissions were of sufficient concern from a health perspective to warrant regulation.

3. EPA Reasonably Based the Appropriate Determination in Part on the Availability of Controls for HAP Emissions From EGUs

In addition to determining that it was appropriate to regulate because of the known and potential hazards to public health and the environment, EPA also concluded that it was appropriate to regulate HAP emissions from EGUs because EPA had identified a number of control options that would effectively reduce HAP emissions from EGUs. 65 FR 79828–30. EPA discussed the various controls available to reduce HAP emissions from EGUs in the December 2000 Finding. The approach of section 112, as amended in 1990, is based on the premise that, to the extent there are controls available to reduce HAP emissions, sources should be required to use them. Thus, it was reasonable to base the appropriate finding in part on the conclusion that controls currently available were expected to reduce HAP emissions from EGUs.

4. EPA Reasonably Concluded It Was Necessary To Regulate EGUs

In 2000, EPA found it was necessary to regulate HAP emissions from EGUs under section 112 because the imposition of the other requirements of the CAA would not address the serious public health and environmental hazards arising from such emissions. 65 FR 79830. EPA also noted that Congress enacted section 112 specifically to address HAP emissions from stationary sources, and it was thus reasonable to regulate HAP emissions from EGUs under that section given the hazards to public health and the environment posed by such emissions. *Id.*

In Table 1 of the December 20, 2000 notice, EPA set forth its projections of HAP emissions for 2010. In assessing those projections in 2000, EPA considered the data that it had obtained as the result of the 1999 ICR. 65 FR 79828. It also considered projected changes in the population of units, fuel consumption, and control device configuration. *Id.* EPA considered control device configurations in making the 2010 projections, in an effort to account for the reductions attributable to the imposition of other requirements of the CAA.

Specifically, in estimating the projected 2010 HAP emissions from EGUs, EPA accounted for the HAP reductions that would occur as the result of the controls required to comply with the ARP. Congress added the ARP in CAA Title IV, as part of the 1990 amendments, and that program is primarily directed at EGUs. EPA, therefore, considered the HAP reductions projected to occur as the result of control configurations needed to meet the Acid Rain requirements of the CAA. *See, e.g.,* Utility Study, ES–2.

As shown in Table 1 of the December 20, 2000 notice, EPA estimated that the level of all HAP emitted by coal-fired EGUs would increase by 2010. 65 FR 79828 (Table 1). For Hg, EPA estimated that EGUs emitted 46 tons of Hg in 1990 and 43 tons of Hg in 1999, and it projected that EGUs would emit approximately 60 tons of Hg in 2010. 65 FR 79827–828. EPA also estimated an overall increase in non-Hg HAP emissions from coal-fired EGUs. Given these estimates and projections, which were based on the best information available at the time, EPA reasonably concluded that the identified and potential hazards associated with HAP from coal-fired EGUs would not be addressed through imposition of the other requirements of the CAA.

For oil-fired EGUs, EPA projected a decline in overall HAP emissions. The decline was primarily due to projected retirements and fuel switching from oil to natural gas. EPA could not conclude based on the information available at the time that the facilities posing the cancer risks, due primarily to Ni emissions, would retire or change fuels. As a result of these uncertainties and the uncertainties as to the extent of the public health impact from oil-fired units, EPA found that it was necessary to regulate such units under section 112.

5. The 2005 Action: EPA Erred in the 2005 Action by Concluding That the December 2000 Finding Lacked Foundation

In 2005, the Agency asserted that the December 2000 Finding lacked foundation for two reasons. First, the Agency stated that the 2000 appropriate finding was overbroad to the extent it relied on adverse environmental effects. Second, the Agency stated that the 2000 appropriate finding lacked foundation because EPA did not fully consider the Hg emissions remaining after imposition of the requirements of the CAA. For the reasons provided below, we reject these assertions as unfounded. As demonstrated above, EPA's 2000 appropriate and necessary finding was sound and fully supported by the record before the Agency in 2000.

a. Consideration of Environmental Effects in the Appropriate Finding

EPA reasonably examined the adverse environmental impacts associated with Hg in making the December 2000 Finding. In 2005, EPA changed its interpretation of the broad term “appropriate” to restrict the consideration of environmental effects only to situations where the Agency had determined that a hazard to public health exists as a result of EGU HAP emissions. As such, EPA stated in 2005 that the December 2000 Finding lacked foundation to the extent it was based on environmental effects.

As explained above in Section III.A, EPA's 2005 change in how it interpreted the term “appropriate” lacks merit. Congress gave EPA broad discretion to determine whether it was appropriate to regulate EGUs under section 112. On the one hand, EPA recognized that broad discretion in 2005, but on the other hand, it sought to limit that discretion by only allowing environmental impacts to be considered if a hazard to public health was found. The 2005 interpretation was based on the flawed notion that the Agency should only consider health effects because the Utility Study only required consideration of hazards to public health. But, as noted above, Congress specifically directed EPA in section 112(n)(1)(B) to consider the environmental effects associated with Hg emissions from EGUs. It was entirely reasonable, therefore, for EPA to consider such effects in making its appropriate finding in 2000.

Furthermore, even under the Agency's flawed 2005 interpretation, which allowed consideration of environmental effects only where a hazard to public health exists, EPA properly considered environmental effects in 2000 because we, in fact, found a hazard to public health based on the record at that time.

b. Scope of “Appropriate” Finding

EPA interprets the “appropriate” finding to require an evaluation of the hazards to public health and the environment at the time of the finding. This interpretation is consistent with the approach taken in 2000. By contrast, in the 2005 “appropriate” analysis, EPA considered the hazards to public health that were reasonably anticipated to occur “after imposition of the requirements of the Act.” In short, EPA infused the “after imposition of the requirements of the Act” inquiry into both the appropriate and necessary prongs.

As explained in Section III.A, this interpretation improperly conflates the "appropriate" and "necessary" analysis. Accordingly, any assertion that EPA's 2000 appropriate finding is flawed because the Agency failed to consider the other requirements of the CAA should be rejected.

Even considering the Agency's flawed 2005 interpretation of the term "appropriate," there is nothing in the record to suggest that the Agency erred in 2000 with regard to assessing Hg emissions. As explained above, in 2000, EPA reasonably considered those requirements of the CAA that directly pertained to EGUs (*i.e.,* the ARP in Title IV of the Act).

In addition, in 2000, EPA recognized that EGUs may be subject to requirements pursuant to SIP developed in response to NAAQS. In fact, EPA had projected a potential 11 tpy reduction in EGU Hg emissions as the result of the ozone and PM NAAQS. Utility Study, p. 1–3. EPA explained in the Utility Study, however, why it did not account for such reductions in its 2010 emission projections.

First, EPA explained that some of the Hg reductions associated with the PM and ozone NAAQS would be realized through the implementation of the ARP, and, thus, had already been accounted for in its 2010 projections. *See* Utility Study, page 1–3. Thus, to consider the projected reductions from the NAAQS would have potentially led to double counting of the estimated HAP reductions. Second, the states, not EPA, are primarily responsible for implementation of the NAAQS. EPA could not have reasonably assumed that the estimated Hg reductions from EGUs would occur because it could not forecast the prospective regulatory actions of the states and the impact that those actions would have on HAP emissions. In short, there was no guarantee that states would regulate EGUs to achieve the reductions necessary to meet the NAAQS in such a way that would achieve Hg reductions, and EPA reasonably did not consider such possible reductions in its 2000 analysis.

Furthermore, at the time of the Utility Study, no areas had been designated as nonattainment with the 1997 revised PM NAAQS. *See* Utility Study, page 2–32. Even had all areas been designated at the time of the Utility Study, we still would not have known how the states would have elected to obtain the required reductions to meet the NAAQS. We also would not have had information as to how the sources would actually implement the requirements in any SIP, and as noted above, the degree of HAP co-benefit reductions varies depending on the control approach used. Even had we considered the potential 11 tpy of Hg reductions estimated to occur as a result of implementing the 1997 NAAQS, the projected level of Hg emissions from EGUs in 2010 would have been 49 tpy ($60 - 11 = 49$), which is still 6 tpy greater than the 43 tpy that the Agency concluded in 2000 caused a hazard to public health and the environment. Thus, even if the NAAQS had been included in the 2010 projections, the Agency would still have found that the identified hazards would not be resolved through imposition of the requirements of the CAA and would have concluded it was necessary to regulate EGUs under section 112.

EPA also asserted in 2005 that it failed to account for Hg reductions associated with the 1997 Utility NSPS in assessing whether it was appropriate to regulate in 2000. In the Utility Study, EPA noted that EGUs would be implementing the same controls for NO_X and SO_2 to meet the requirements of both Title I and Title IV. EPA accounted for the ARP in its 2010 projections. In addition, in the Utility Study, EPA determined that HAP emissions from EGUs would increase in 2010 based on estimated increases in coal use, which was primarily projected to occur at new units. Utility Study, pages 2–26 to 2–31. Because EPA was unable to determine the size and location of the new units at the time of the Utility Study, the Agency reasonably allocated the increased fuel consumption to existing units (excluding the coal-fired units that were projected to retire between 1990 and 2010). All or a substantial majority of existing units already had some type of PM control and many units had scrubbers. To the extent this approach of assigning increased fuel consumption to existing controlled units led to an overestimation of remaining HAP emissions, we do not believe the overestimation was significant. EPA's approach to projecting emissions in 2010 was entirely reasonable given the data and information available to the Agency at the time. *See* Utility Study, page 6–15.

Finally, EPA asserted in 2005 that it failed to account for the Hg reductions associated with the NO_X SIP call. Like the NAAQS, states are primarily responsible for developing regulations to meet the NO_X SIP call. EPA could not have reasonably assumed that the estimated Hg reductions from EGUs would occur because it could not forecast the prospective regulatory actions of the states. In addition, in 2005, EPA neither identified the reductions that would occur as the result of the NO_X SIP call, nor explained how those reductions would have changed EPA's 2000 appropriate finding.

EPA solicits comment on section III.B.

C. EPA Must Regulate EGUs Under Section 112 Because EGUs Were Properly Listed Under CAA Section 112(c)(1) and may not be Delisted Because They do not Meet the Delisting Criteria in CAA Section 112(c)(9)

As shown above, in 2000, EPA reasonably determined, based on the record before it at the time, that it was appropriate and necessary to regulate EGUs under CAA section 112. Once that finding was made, EPA properly listed EGUs pursuant to section 112(c), and EGUs remain a listed source category. *See New Jersey,* 517 F.3d at 583.

As the DC Circuit Court held in *New Jersey,* EPA cannot ignore the delisting criteria in section 112(c)(9). CAA section 112(c)(9)(B) authorizes the Agency to delist any source category if the Agency determines that: (1) For HAP that may cause cancer in humans, no source in the category emits such HAP in quantities that "may cause a lifetime risk of cancer greater than one in one million" to the most exposed individual; section 112(c)(9)(B)(i); and (2) for HAP that may result human health effects other than cancer or adverse environmental effects, "emissions from no source in the category or subcategory concerned * * * exceeds a level which is adequate to protect public health with an ample margin of safety and no adverse environmental effect will result from emissions from any source." Section 112(c)(9)(B)(ii).

Here, we have a validly listed source category. EPA could not have met the delisting criteria in 2000 or 2005, and it still cannot meet those criteria today.

The information in the Utility Study shows that HAP emissions from a number of EGUs caused a lifetime cancer risk greater than one in one million. Nothing in the 2005 record suggested anything to the contrary, and as such, the Agency did not delist EGUs in 2005 pursuant to section 112(c)(9). Finally, EPA has conducted 16 case studies based on the data collected in support of this proposed rule and determined that 4 of those facilities evaluated (25 percent) presented a lifetime cancer risk greater than 1 in 1 million. Thus, based on current data and analysis, EGUs fail the first requirement for delisting set forth in section 112(c)(9)(B)(i). Because EGUs do not meet the first delisting requirement, the Agency need not determine whether the second delisting requirement is satisfied; however, the Agency believes that EGUs would similarly fail the second delisting requirement for the reasons described below in section III.D.

D. New Analyses Confirm That it Remains Appropriate and Necessary to Regulate U.S. EGU HAP Under Section 112

As explained above, the December 2000 appropriate and necessary determination is wholly supported by the record that was before the Agency at the time it made its decision. Although not required, we conducted additional technical analyses because several years have passed since the December 2000 Finding. These extensive analyses confirm that it remains appropriate and necessary today to regulate EGUs under section 112. We discuss below the new analyses that we conducted. We also explain why these analyses and the other information currently before the Agency confirm that regulation of EGUs under section 112 is appropriate and necessary. We solicit comment on the new analyses.

Utilities are by far the largest remaining source of Hg in the U.S.[26] In addition, EGUs are the largest source of HCl, HF, and Se emissions, and a major source of metallic HAP emissions including As, Cr, Ni, and others.[27] The discrepancy is even greater now that almost all other major source categories have been required to control Hg and other HAP under section 112.

These significant HAP emissions pose a known or potential hazard to public health and the environment and, thus, it remains appropriate to regulate EGUs under section 112.

In this section, we describe briefly the health and environmental effects associated with the HAP emitted by EGUs and summarize the new analyses that the Agency conducted to assess the hazards to public health and the environment associated with EGU emissions, including the hazards remaining after imposition of the requirements of the CAA. We then discuss our conclusion that it remains appropriate and necessary to regulate EGUs under section 112.

Specifically, we conclude today that it remains appropriate to regulate EGUs under section 112 because Hg is a persistent, bioaccumulative pollutant, and emissions of Hg from EGUs continue to pose a hazard to public health and to the environment. Because of the persistent nature of Hg in the environment, Hg emitted today can lead to re-emissions of Hg in the future, and as a result continue to contribute to Hg deposition and associated health and environmental hazards in the future.

In addition, we conclude today that it is appropriate to regulate non-Hg HAP because emissions of these HAP from some EGUs pose a cancer risk greater than one in one million to the most exposed individual.[28] EGUs remain the largest contributors of several HAP (*e.g.,* HF, Se, HCl), and are among the largest contributor for other HAP (*e.g.,* As, Cr, Ni, hydrogen cyanide (HCN)).[29] EPA recognizes that there are additional health and environmental effects for which we have insufficient information to quantify risks, or which have a higher degree of uncertainty regarding the weight of evidence for causality. While not quantified in our analysis, the potential for additional hazards to public health and the environment beyond what we have analyzed provides additional support for regulation under section 112 that will assure reductions of all HAP and the risks, quantified or unquantified, that they pose.

Finally, we find that it remains appropriate to regulate EGUs under section 112 because we have identified a number of currently available control technologies that will adequately address HAP emissions from EGUs. Several of these findings provide an independent basis for our determination consistent with our interpretation of the appropriate finding set forth above, and the combined weight of these findings provides a strong overall basis for our determination that it is and remains appropriate to regulate EGUs under CAA section 112.

We conclude that it remains necessary to regulate HAP emissions from EGUs because the imposition of the requirements of the CAA will not sufficiently address the hazards to public health and the environment posed by Hg emissions or the cancer risk and potential hazards to the environment posed by non-Hg HAP emissions from EGUs. Although the identified hazards will not be fully addressed through regulation under section 112, there will be a significant reduction in domestic Hg and non-Hg HAP emissions as the result of a section 112 regulation. EGUs remain the largest source of HCl and HF emissions in the U.S., and it is essential that those emissions be reduced to the maximum extent achievable, as Congress envisioned pursuant to section 112. Furthermore, it is necessary to regulate EGUs under section 112 because standards under that section assure that reductions in HAP emissions from EGUs will be permanently realized, thereby assuring that recent decreases in HAP emissions from U.S. EGUs will not be reversed in the future. Each of these conclusions independently supports our determination that it remains necessary to regulate EGUs under section 112.

Below we present an overview of EPA's current view of the scientific and technical information relevant to evaluating U.S. EGU Hg emissions and the public health hazards associated with such emissions. We provide general background information on the health hazards and environmental impacts of Hg and its transformation product MeHg; the emissions of those pollutants; the U.S. EGU contribution to these emissions; the predominant exposure pathway by which humans are affected by MeHg, which is by ingestion of fish containing MeHg; EPA's methodology for determining the impacts of U.S. EGU Hg emissions on potential exposures to MeHg in fish; the estimated potential risks associated with recent and future anticipated emissions of Hg from U.S. EGUs; and a qualitative analysis of the environmental hazards associated with Hg deposition. In addition to these analyses of hazards to public health and the environment associated with emissions of Hg from U.S. EGUs, this section also includes analyses of the hazards to public health and the environment from U.S. EGU emissions of non-Hg HAP. We then explain why the hazards to public health and the environment from Hg and non-Hg HAP emissions are reasonably anticipated to remain from U.S. EGUs after imposition of the requirements of the CAA. Finally, we discuss our evaluation of the new data and our finding that it remains appropriate and necessary to regulate EGUs under section 112.

1. Background Information on Hg Emissions, Deposition, and Effects on Human Health and the Environment

a. Overview of Hg and Associated Health and Environmental Hazards

Mercury is a persistent, bioaccumulative toxic metal that is emitted from EGUs in three forms:

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[26] Strum, M., Houyoux, M., U.S. Environmental Protection Agency. Emissions Overview: Hazardous Air Pollutants in Support of the Proposed Toxics Rule. Memorandum to Docket EPA–HQ–OAR–2009–0234. March 15, 2011.

[27] Ibid. Tables 3 and 4.

[28] Strum, M., Thurman, J., and Morris, M., U.S. Environmental Protection Agency. Non-Hg Case Study Chronic Inhalation Risk Assessment for the Utility MACT "Appropriate and Necessary" Analysis. Memorandum to Docket EPA–HQ–OAR–2009–0234. March 1, 2011.

[29] Strum, M., Houyoux, H., op. cit., Tables 3 and 4.

Gaseous elemental Hg (Hg^0), oxidized Hg compounds (Hg^{+2}), and particle-bound Hg (Hg_P). Elemental Hg does not quickly deposit or chemically react in the atmosphere, resulting in residence times that are long enough to contribute to global scale deposition. Oxidized Hg and Hg_P deposit quickly from the atmosphere impacting local and regional areas in proximity to sources. Methylmercury is formed by microbial action in the top layers of sediment and soils, after Hg has precipitated from the air and deposited into waterbodies or land. Once formed, MeHg is taken up by aquatic organisms and bioaccumulates up the aquatic food web. Larger predatory fish may have MeHg concentrations many times, typically on the order of one million times, that of the concentrations in the freshwater body in which they live. Although Hg is toxic to humans when it is inhaled or ingested, we focus in this rulemaking on exposure to MeHg through ingestion of fish, as it is the primary route for human exposures in the U.S., and potential health risks do not likely result from Hg inhalation exposures associated with Hg emissions from utilities.

In 2000, the National Research Council (NRC) of the NAS issued the NAS Study, which provides a thorough review of the effects of MeHg on human health. There are numerous studies that have been published more recently that report effects on neurologic and other endpoints.

i. Reference and Benchmark Doses

As discussed earlier in Sections II.A.1 and III.B.3.a.i of this preamble, EPA has set and evaluated the RfD for Hg several times, and has received input from the NRC on the appropriateness of the RfD. In 1995, EPA set a health-based ingestion rate for chronic oral exposure to MeHg termed an oral RfD, at 0.0001 milligrams per kilogram per day (mg/kg-day).[30] The RfD was based on effects reported for children exposed *in utero* during the Iraqi Hg poisoning episode, in which children were exposed to high levels of Hg when their mothers consumed contaminated grain.[31] Subsequent research from large epidemiological studies in the Seychelles,[32] Faroe Islands,[33] and New Zealand [34] added substantially to the body of knowledge on neurological effects from MeHg exposure. In 2001 EPA established a revised RfD based on the advice of the NAS and an independent review panel convened as part of the Integrated Risk Information System (IRIS) process. In their analysis, the NAS examined in detail the epidemiological data from the Seychelles, the Faroe Islands, and New Zealand, as well as other toxicological data on MeHg. The NAS recommended that neurobehavioral deficits as measured in several different tests among these studies be used as the basis for the RfD.

The NAS proposed that the Faroe Islands cohort was the most appropriate study for defining an RfD, and specifically selected children's performance on the Boston Naming Test (a neurobehavioral test) as the key endpoint. Results from all three studies were considered in defining the RfD, as published in the "2001 Water Quality for the Protection of Human Health: Methylmercury," and in the IRIS summary for MeHg: "Rather than choose a single measure for the RfD critical endpoint, EPA based this RfD for this assessment on several scores from the Faroes' measures, with supporting analyses from the New Zealand study, and the integrative analysis of all three studies." [35]

EPA defined the updated RfD of 0.0001 mg/kg-day in 2001. Although derived from a more complete data set and with a somewhat different methodology, the current RfD is numerically the same as the previous (1995) RfD (0.0001 mg/kg-day, or 0.1 µg/kg-day).

This RfD, consistent with the standard definition, is an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime (EPA, 2002). In general EPA believes that exposures at or below the RfD are unlikely to be associated with appreciable risk of deleterious effects. However, no RfD defines an exposure level corresponding to zero risk; moreover the RfD does not represent a bright line, above which individuals are at risk of adverse effects. EPA's interpretation for this assessment is that any exposures to MeHg above the RfD are of concern given the nature of the data available for Hg that is not necessarily available for many other chemicals. The scientific basis for the Hg RfD includes extensive human data and extensive data on sensitive subpopulations, including pregnant mothers; therefore, the RfD does not include extrapolations from animals to humans, and from the general population to sensitive subpopulations. In addition, there was no evidence of a threshold for MeHg-related neurotoxicity within the range of exposures in the Faroe Islands study which served as the primary basis for the RfD. This additional confidence in the basis for the RfD suggests that all exposures above the RfD can be interpreted with more confidence as causing a potential hazard to public health. Studies published since the current MeHg RfD was released include new analyses of children's neuropsychological effects from the existing Seychelles and Faroe Islands cohorts, including formation of a new cohort in the Faroe Islands study. There are also a number of new studies that were conducted in population-based cohorts in the U.S and other countries. A comprehensive assessment of the new literature has not been completed by EPA. However, data published since 2001 are generally consistent with those of the earlier studies that were the basis of the RfD, demonstrating persistent effects in the Faroe Island cohort, and in some cases associations of effects with lower MeHg exposure concentrations than in the Faroes. These new studies provide additional confidence that exposures above the RfD are contributing to risk of adverse effects, and that reductions in exposures above the RfD can lead to incremental reductions in risk.

ii. Neurologic Effects

In its review of the literature, the NAS found neurodevelopmental effects to be the most sensitive and best documented endpoints and appropriate for establishing an RfD;[36] in particular NAS

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[30] MeHg exposure is measured as milligrams of MeHg per kilogram of bodyweight per day, thus normalizing for the size of fish meals and the differences in bodyweight among exposed individuals.

[31] Marsh DO, Clarkson TW, Cox C, Myers GJ, Amin-Zaki L, Al-Tikriti S 1987. Fetal methylmercury poisoning. Relationship between concentration in single strands of maternal hair and child effects. Arch Neurol 44(10):1017–1022.

[32] Davidson, P.W., G. Myers, C.C. Cox, C.F. Shamlaye, D.O.Marsh, M.A.Tanner, M. Berlin, J. Sloane-Reeves, E. Chernichiari,, O. Choisy, A. Choi and T.W. Clarkson. 1995. Longitudinal neurodevelopment study of Seychellois children following *in utero* exposure to methylemrcury from maternal fish ingestion: outcomes at 19 and 29 months. NeuroToxicology 16:677–688.

[33] Grandjean, P., Weihe, P., White, R.F., Debes, F., Araki, S., Murata, K., Sørensen, N., Dahl, D., Yokoyama, K., Jørgensen, P.J., 1997. Cognitive deficit in 7-year-old children with prenatal exposure to methylmercury. Neurotoxicol. Teratol. 19, 417–428.

[34] Kjellstrom T, Kennedy P, Wallis S, Stewart A, Friberg L, Lind B, *et al.* (1989). Physical and mental development of children with prenatal exposure to mercury from fish. Stage 2: Interviews and psychological tests at age 6. Solna, Sweden: National Swedish Environmental Protection Board. Report No.: Report 3642.

[35] EPA, 2001.

[36] NAS, 2000.

supported the use of results from neurobehavioral or neuropsychological tests. The NAS report [37] noted that studies in animals reported sensory effects as well as effects on brain development and memory functions and support the conclusions based on epidemiology studies. The NAS noted that their recommended endpoints for an RfD are associated with the ability of children to learn and to succeed in school. They concluded the following: "The population at highest risk is the children of women who consumed large amounts of fish and seafood during pregnancy. The committee concludes that the risk to that population is likely to be sufficient to result in an increase in the number of children who have to struggle to keep up in school."

iii. Cardiovascular Impacts

The NAS summarized data on cardiovascular effects available up to 2000 (IRIS 2001). Based on these and other studies, the NRC (2000) concluded that "Although the data base is not as extensive for cardiovascular effects as it is for other end points (*i.e.,* neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals." The NRC also stated that "additional studies are needed to better characterize the effect of methylmercury exposure on blood pressure and cardiovascular function at various stages of life."

Additional cardiovascular studies have been published since 2000. EPA did not to develop a quantitative dose-response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail Hg levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

iv. Genotoxic Effects

The Mercury Study noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NAS concluded that evidence that human exposure to MeHg caused genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders. One study of adults living in the Tapajós River region in Brazil [38] reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes; as well as effects on chromosomes. Long-term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary, chronic MeHg exposures similar to and above those seen in the Faroes and Seychelles populations.

v. Immunotoxic Effects

Although exposure to some forms of Hg can result in a decrease in immune activity or an autoimmune response,[39] evidence for immunotoxic effects of MeHg is limited.[40]

vi. Other Human Toxicity Data

Based on limited human and animal data, MeHg is classified as a "possible" human carcinogen by the International Agency for Research on Cancer (IARC) [41] and in IRIS.[42] The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between Hg exposure and overall cancer incidence, although a few studies have shown an association between Hg exposure and specific types of cancer incidence (*e.g.,* acute leukemia and liver cancer [43]).

There is also some evidence of reproductive and renal toxicity in humans from MeHg exposure. However, overall, human data regarding reproductive, renal, and hematological toxicity from MeHg are very limited and are based on either studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis.

b. Mercury Emissions

Mercury is an element. There is a fixed amount of it in the world. As long as it is bound up, for example in coal, it cannot affect people or the environment. Once it is released, for example via the combustion process, it enters the environment and becomes available for chemical conversion. Once emitted, Hg remains in the environment, and can bioaccumulate in organisms or be remitted through natural processes. Mercury is emitted through natural and anthropogenic processes; in addition, previously deposited Hg from either process may be re-emitted. Mercury deposition in the U.S. is not directly proportional to total Hg emissions, due to the differing rates at which the three species of Hg (Hg^0, Hg^{+2}, Hg_p) deposit. In general, the greater the fraction of total Hg accounted for by Hg^{+2} and Hg_P, the higher the correlation between total Hg emissions and total Hg deposition in the U.S. In the following discussion, we will be describing emissions of Hg, while we discuss deposition later in this section.

The categories for anthropogenic Hg emissions include the combustion of fossil-fuels, cement production, waste incineration, metals production, and other industrial processes. Anthropogenic Hg emissions consist of Hg^0, Hg^{+2}, and Hg_P.

Mercury re-emissions include previously deposited Hg originating from both natural and anthropogenic sources. At this time, it is not possible to determine the original source of previously deposited Hg, whether its source is natural emissions or re-emissions from previously deposited anthropogenic Hg.[44] [45] [46] It is believed that half of re-emitted Hg originates from anthropogenic sources.[47] [48]

Current estimates of total global Hg emissions based on a 2005 inventory

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[37] NAS, 2000.

[38] Amorim, M.I., Mergler, D., Bahia, M.O., Dubeau, H., Miranda, D., Lebel, J., Burbano, R.R., Lucotte, M., 2000. Cytogenetic damage related to low levels of methyl mercury contamination in the Brazilian Amazon. An. Acad. Bras. Cienc. 72, 487–507.

[39] Agency for Toxic Substances and Disease Registry (ATSDR). 1999. Toxicological profile for Mercury. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. *http://www.atsdr.cdc.gov/toxprofiles/tp.asp?id=115&tid=24.*

[40] National Academy of Sciences. Toxicologic effects of methylmercury. Washington, DC: National Research Council, 2000. Available online at *http://www.nap.edu/openbook.php?isbn=0309071402.*

[41] IARC, 1994.

[42] EPA, 2002.

[43] NAS, 2000.

[44] Lindberg, S., Bullock, R., Ebinghaus, R., Engstrom, D., Feng, X., Fitzgerald, W., *et al.* (2007). A Synthesis of Progress and Uncertainties in Attributing the Sources of Mercury in Deposition. *Ambio, 36*(1), 19–33.

[45] Lohman, K., Seigneur, C., Gustin, M., & Lindberg, S. (2008). Sensitivity of the global atmospheric cycle of mercury to emissions. *Applied Geochemistry,* 23(3), 454–466.

[46] Seigneur, C., Vijayaraghavan, K., Lohman, K., Karamchandani, P., & Scott, C. (2004). Global Source Attribution for Mercury Speciation in the United States. *Environmental Science and Technology*(38), 555–569.

[47] Mason, R., Pirrone, N., & Mason, R. P. (2009). Mercury emissions from natural processes and their importance in the global mercury cycle. In *Mercury Fate and Transport in the Global Atmosphere* (pp. 173–191): Springer U.S.

[48] Selin, N. E., Jacob, D. J., Park, R. J., Yantosca, R. M., Strode, S., Jaeglé, L., et al. (2007). Chemical cycling and deposition of atmospheric mercury: Global constraints from observations. *J. Geophys. Res,* 112, 1071–1077.

range from 7,300 to 8,300 tpy.[49] [50] The United Nations Environment Programme (UNEP) estimates of 2005 global Hg emissions are somewhat lower, at 5,600 metric tpy.[51] Global anthropogenic Hg emissions, excluding biomass burning, have been estimated by many researchers. UNEP's 2005 estimate is approximately 2,100 tpy (with a range of 1,300 tpy to 3,300 tpy) [52] and Pirrone, *et al.'s* 2005 estimate is approximately 2,600 tpy. Global fossil-fuel fired EGUs total approximately 500 to 900 tpy, a large fraction (25 to 35 percent) of the total global anthropogenic emissions.[53] [54] The U.S. contribution to global anthropogenic emissions has declined from 10 percent in 1990 to 5 percent in 2005, due to reductions in U.S. emissions and increases in emissions from other countries.[55]

Although total U.S. anthropogenic Hg has decreased, the EGU sector remains the largest contributor to the total. In 1990, U.S. EGU Hg emissions for coal-fired units above 25 MW were 46 tons out of total U.S. Hg emissions of 264 tons.[56] By 1999 U.S. EGU Hg emissions for coal-fired units above 25 MW were 43 out of 115 tons.[57] In 2005, estimated emissions for coal- and oil-fired units above 25 MW were 53 tons out of a total of 105 tons. However, the 2005 estimate is based on control configurations as of 2002; therefore, it does not reflect reductions due to control installations that took place between 2002 and 2005. A current estimate of Hg emissions for both coal- and oil-fired units above 25 MW, using data from the EPA's 2010 ICR database, which used testing data for over 300 units, is 29 tons of Hg. We believe our estimate of the current level of Hg emissions based on the 2010 ICR database may underestimate total EGU Hg emissions due to the fact that emission factors used to develop the estimates may not accurately account for larger emissions from units with more poorly performing emission controls. EPA tested only 50 randomly selected units that were not selected for testing as best performing units (the bottom 85 percent of units), and we used that small sample to attempt to characterize the lower performing units. Because the 50 units were randomly selected, we do not believe we have sufficiently characterized the units that have poorly performing controls. In addition, the 2010 estimate also reflects the installation of Hg controls to comply with state Hg-specific rules, voluntary reductions from EGUs, and the co-benefits of Hg reductions associated with control devices installed for the reduction of SO_2 and PM as a result of state and Federal actions, such as New Source Review (NSR) enforcement actions and implementation of CAIR. Table 3 shows U.S. EGU Hg emissions along with emissions from other major non-EGU Hg sources. Table 3 also shows EPA's projection that U.S. EGU emissions will continue to comprise a dominant portion of the total U.S. anthropogenic inventory in 2016. In 2016, U.S. EGU Hg emission for the subset of coal-fired units above 25 MW is projected to be 29 tons out of a total of 64 tons.[58]

TABLE 3—ANTHROPOGENIC HG EMISSIONS AND PROJECTIONS IN THE U.S.*

Category	2005 Mercury (tons)	2016 Mercury (tons)
Electric Generating Units	53	29
Portland Cement Manufacturing	7.5	1.1
Stainless and Nonstainless Steel Manufacturing: Electric Arc Furnaces	7.0	4.6
Industrial, Commercial, Institutional Boilers & Process Heaters	6.4	4.6
Chemical Manufacturing	3.3	3.3
Hazardous Waste Incineration	3.2	2.1
Mercury Cell Chlor-Alkali Plants	3.1	0.3
Gold Mining	2.5	0.7
Municipal Waste Combustors	2.3	2.3
Sum of other source categories (each of which emits less than 2 tons)	17	16
Total	105	64

* Emissions estimates are presented at a maximum of two significant figures.

c. Atmospheric Processing and Deposition of Hg

Mercury is known to exist in the atmosphere in three forms: Hg^0, Hg^{+2}, and Hg_P. The dominant form of Hg in the atmosphere is Hg^0.[59] Elemental Hg dominates total Hg composition in the atmosphere (greater than 95 percent) and has a much greater residence time than Hg^{+2} or Hg_P. Elemental Hg has a long atmospheric residence time due to its near insolubility in water and high vapor pressure which minimize removal through wet and dry deposition processes.[60] Oxidized Hg (which is

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[49] Lindberg, S., Bullock, R., Ebinghaus, R., Engstrom, D., Feng, X., Fitzgerald, W., *et al.* (2007). A Synthesis of Progress and Uncertainties in Attributing the Sources of Mercury in Deposition. *Ambio, 36*(1), 19–33.

[50] Pirrone, N., Cinnirella, S., Feng, X., Finkelman, R. B., Friedli, H. R., Leaner, J., *et al.* (2010). Global mercury emissions to the atmosphere from anthropogenic and natural sources. *Atmospheric Chemistry and Physics Discussions, 10*(2), 4719–4752.

[51] UNEP (United Nations Environment Programme), Chemicals Branch, 2008. The Global Atmospheric Mercury Assessment: Sources, Emissions and Transport, UNEP Chemicals, Geneva.

[52] Study on Mercury Sources and Emissions and Analysis of the Cost and Effectiveness of Control Measures "UNEP Paragraph 29 study", UNEP (DTIE)/Hg/INC.2/4. November, 2010.

[53] Pirrone, N., Cinnirella, S., Feng, X., Finkelman, R. B., Friedli, H. R., Leaner, J., et al. (2010). Global mercury emissions to the atmosphere from anthropogenic and natural sources. *Atmospheric Chemistry and Physics Discussions, 10*(2), 4719–4752.

[54] Study on Mercury Sources and Emissions and Analysis of the Cost and Effectiveness of Control Measures "UNEP Paragraph 29 study", UNEP (DTIE)/Hg/INC.2/4. November, 2010.

[55] The estimate of 5 percent is based upon 105 tons in 2005 divided by 2,100 tons from UNEP.

[56] The 46 ton estimate is based on the Utility Study. Since that time, EPA has updated its estimate of U.S. EGU Hg emissions in 1990. The updated estimate is 59 tons.

[57] Since the December 2000 Finding, the NEI process has led to an updated emissions estimate of 49 tons.

[58] As explained further in the emissions modeling TSD, this projection does not include reductions from a number of state-only Hg regulations and voluntary Hg reductions programs that are not Federally enforceable, and are not relevant to our assessment of whether it is appropriate and necessary to regulate U.S. EGU sources under section 112.

[59] Schroeder, W. H. and J. Munthe (1998). "Atmospheric mercury—An overview." *Atmospheric Environment* 32(5): 809–822.

[60] Schroeder, W. H. and J. Munthe (1998). "Atmospheric mercury—An overview." *Atmospheric Environment* 32(5): 809–822.

soluble) and Hg_P are more readily scavenged by precipitation and have higher dry deposition velocities than Hg^0 resulting in much shorter residence times. Although natural sources such as land, ocean and volcanic Hg are emitted as elemental, most anthropogenic sources are emitted in all three forms. EGU Hg ranges from 20 to 40 percent Hg^{+2} and from 2 to 5 percent Hg_p. This results in greater deposition of Hg^{+2} and Hg_P within the U.S. due to U.S. EGU emissions of these two Hg species, relative to emissions of Hg^0. As a result, control of emissions of Hg^{+2} and Hg_P are more relevant for decreasing U.S. EGU-attributable exposures to MeHg for recreational and subsistence-level fish consumers than control of emissions of Hg^0. Control of emissions of Hg^0 will still have value in reducing overall global levels of Hg deposition, and will, all else equal, eventually result in lower global fish MeHg concentrations which can benefit both U.S. and global populations.

2. Background Information on Non-Hg HAP Emissions and Effects on Human Health and the Environment

a. Overview of Non-Hg HAP and Associated Health and Environmental Hazards

Emissions data collected through the 2010 ICR during development of this proposed rule show that HCl emissions represent the predominant HAP emitted by U.S. EGUs. Coal- and oil-fired EGUs emit lesser amounts of HF, chlorine (Cl_2), metals (As, Cd, Cr, Hg, Mn, Ni, and Pb), and organic HAP emissions. Although numerous organic HAP may be emitted from coal- and oil-fired EGUs, only a few account for essentially all the mass of organic HAP emissions. These organic HAP are formaldehyde, benzene, and acetaldehyde.

Exposure to high levels of the various non-Hg HAP emitted by EGUs is associated with a variety of adverse health effects. These adverse health effects include chronic (long-term) health disorders (*e.g.,* effects on the central nervous system, damage to the kidneys, and irritation of the lung, skin, and mucus membranes); and acute health disorders (*e.g.,* effects on the kidney and central nervous system, alimentary effects such as nausea and vomiting, and lung irritation and congestion). EPA has classified three of the HAP emitted by EGUs as human carcinogens and five as probable human carcinogens. The following sections briefly discuss the main health effects information we have regarding the key HAP emitted by EGUs in alphabetical order by HAP name.

i. Acetaldehyde

Acetaldehyde is classified in EPA's IRIS database as a probable human carcinogen, based on nasal tumors in rats, and is considered toxic by the inhalation, oral, and intravenous routes.[61] Acetaldehyde is reasonably anticipated to be a human carcinogen by the U.S. Department of Health and Human Services (DHHS) in the 11th Report on Carcinogens and is classified as possibly carcinogenic to humans (Group 2B) by the IARC.[62] [63] The primary noncancer effects of exposure to acetaldehyde vapors include irritation of the eyes, skin, and respiratory tract.[64]

ii. Arsenic

Arsenic, a naturally occurring element, is found throughout the environment and is considered toxic through the oral, inhalation and dermal routes. Acute (short-term) high-level inhalation exposure to As dust or fumes has resulted in gastrointestinal effects (nausea, diarrhea, abdominal pain, and gastrointestinal hemorrhage); central and peripheral nervous system disorders have occurred in workers acutely exposed to inorganic As. Chronic (long-term) inhalation exposure to inorganic As in humans is associated with irritation of the skin and mucous membranes. Chronic inhalation can also lead to conjunctivitis, irritation of the throat and respiratory tract and perforation of the nasal septum.[65] Chronic oral exposure has resulted in gastrointestinal effects, anemia, peripheral neuropathy, skin lesions, hyperpigmentation, and liver or kidney damage in humans. Inorganic As exposure in humans, by the inhalation route, has been shown to be strongly associated with lung cancer, while ingestion of inorganic As in humans has been linked to a form of skin cancer and also to bladder, liver, and lung cancer. EPA has classified inorganic As as a Group A, human carcinogen.[66]

iii. Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[67] [68] [69] EPA states in its IRIS database that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The IARC has determined that benzene is a human carcinogen and the DHHS has characterized benzene as a known human carcinogen.[70] [71]

A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[72] [73]

Marsik, F. J., G. J. Keeler, *et al.* (2007). "The dry-deposition of speciated mercury to the Florida Everglades: Measurements and modeling." *Atmospheric Environment* 41(1): 136–149.

[61] U.S. Environmental Protection Agency (U.S. EPA). 1991. Integrated Risk Information System File of Acetaldehyde. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at *http://www.epa.gov/iris/subst/0290.htm.*

[62] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: *http://ntp.niehs.nih.gov/go/16183.*

[63] International Agency for Research on Cancer (IARC). 1999. Re-evaluation of some organic chemicals, hydrazine, and hydrogen peroxide. IARC Monographs on the Evaluation of Carcinogenic Risk of Chemical to Humans, Vol 71. Lyon, France.

[64] U.S. Environmental Protection Agency (U.S. EPA). 1991. Integrated Risk Information System File of Acetaldehyde. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at *http://www.epa.gov/iris/subst/0290.htm.*

[65] Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Arsenic. Atlanta, GA: U.S. Department of Health and Human Services. Available on the Internet at *http://www.atsdr.cdc.gov/mhmi/mmg168.html#bookmark02.*

[66] U.S. Environmental Protection Agency (U.S. EPA). 1998. Integrated Risk Information System File for Arsenic. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: *http://www.epa.gov/iris/subst/0278.htm.*

[67] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: *http://www.epa.gov/iris/subst/0276.htm.*

[68] International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345–389, 1982.

[69] Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691–3695.

[70] International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[71] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: *http://ntp.niehs.nih.gov/go/16183.*

[72] Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193–197.

Continued

iv. Cadmium

Breathing air with lower levels of Cd over long periods of time (for years) results in a build-up of Cd in the kidney, and if sufficiently high, may result in kidney disease. Lung cancer has been found in some studies of workers exposed to Cd in the air and studies of rats that inhaled Cd. DHHS has determined that Cd and Cd compounds are known human carcinogens. IARC has determined that Cd is carcinogenic to humans. EPA has determined that Cd is a probable human carcinogen.[74]

v. Chlorine

The acute (short term) toxic effects of Cl_2 are primarily due to its corrosive properties. Chlorine is a strong oxidant that upon contact with water moist tissue (*e.g.,* eyes, skin, and upper respiratory tract) can produce major tissue damage.[75] Chronic inhalation exposure to low concentrations of Cl_2 (1 to 10 parts per million, ppm) may cause eye and nasal irritation, sore throat, and coughing. Chronic exposure to Cl_2, usually in the workplace, has been reported to cause corrosion of the teeth. Inhalation of higher concentrations of Cl_2 gas (greater than 15 ppm) can rapidly lead to respiratory distress with airway constriction and accumulation of fluid in the lungs (pulmonary edema). Exposed individuals may have immediate onset of rapid breathing, blue discoloration of the skin, wheezing, rales or hemoptysis (coughing up blood or blood-stain sputum). Intoxication with high concentrations of Cl_2 may induce lung collapse. Exposure to Cl_2 can lead to reactive airways dysfunction syndrome (RADS), a chemical irritant-induced type of asthma. Dermal exposure to Cl_2 may cause irritation, burns, inflammation and blisters. EPA has not classified Cl_2 with respect to carcinogenicity.

vi. Chromium

Chromium may be emitted in two forms, trivalent Cr (Cr^{+3}) or hexavalent Cr (Cr^{+6}). The respiratory tract is the major target organ for Cr^{+6} toxicity, for acute and chronic inhalation exposures. Shortness of breath, coughing, and wheezing have been reported from acute exposure to Cr^{+6}, while perforations and ulcerations of the septum, bronchitis, decreased pulmonary function, pneumonia, and other respiratory effects have been noted from chronic exposures. Limited human studies suggest that Cr^{+6} inhalation exposure may be associated with complications during pregnancy and childbirth, but there are no supporting data from animal studies reporting reproductive effects from inhalation exposure to Cr^{+6}. Human and animal studies have clearly established the carcinogenic potential of Cr^{+6} by the inhalation route, resulting in an increased risk of lung cancer. EPA has classified Cr^{+6} as a Group A, human carcinogen. Trivalent Cr is less toxic than Cr^{+6}. The respiratory tract is also the major target organ for Cr^{+3} toxicity, similar to Cr^{+6}. EPA has not classified Cr^{+3} with respect to carcinogenicity.

vii. Formaldehyde

Since 1987, EPA has classified formaldehyde as a probable human carcinogen based on evidence in humans and in rats, mice, hamsters, and monkeys.[76] EPA is currently reviewing recently published epidemiological data. After reviewing the currently available epidemiological evidence, the IARC (2006) characterized the human evidence for formaldehyde carcinogenicity as “sufficient,” based upon the data on nasopharyngeal cancers; the epidemiologic evidence on leukemia was characterized as “strong.”[77] EPA is reviewing the recent work cited above from the National Cancer Institute (NCI) and National Institute for Occupational Safety and Health (NIOSH), as well as the analysis by the CIIT Centers for Health Research and other studies, as part of a reassessment of the human hazard and dose-response associated with formaldehyde.

Formaldehyde exposure also causes a range of noncancer health effects, including irritation of the eyes (burning and watering of the eyes), nose and throat. Effects from repeated exposure in humans include respiratory tract irritation, chronic bronchitis and nasal epithelial lesions such as metaplasia and loss of cilia. Animal studies suggest that formaldehyde may also cause airway inflammation—including eosinophil infiltration into the airways. There are several studies that suggest that formaldehyde may increase the risk of asthma—particularly in the young.[78] [79]

viii. Hydrogen Chloride

Hydrogen chloride is a corrosive gas that can cause irritation of the mucous membranes of the nose, throat, and respiratory tract. Brief exposure to 35 ppm causes throat irritation, and levels of 50 to 100 ppm are barely tolerable for 1 hour.[80] The greatest impact is on the upper respiratory tract; exposure to high concentrations can rapidly lead to swelling and spasm of the throat and suffocation. Most seriously exposed persons have immediate onset of rapid breathing, blue coloring of the skin, and narrowing of the bronchioles. Exposure to HCl can lead to RADS, a chemically- or irritant-induced type of asthma. Children may be more vulnerable to corrosive agents than adults because of the relatively smaller diameter of their airways. Children may also be more vulnerable to gas exposure because of increased minute ventilation per kg and failure to evacuate an area promptly when exposed. Hydrogen chloride has not been classified for carcinogenic effects.[81]

ix. Hydrogen Fluoride

Acute (short-term) inhalation exposure to gaseous HF can cause severe respiratory damage in humans, including severe irritation and pulmonary edema. Chronic (long-term) oral exposure to fluoride at low levels has a beneficial effect of dental cavity prevention and may also be useful for the treatment of osteoporosis. Exposure to higher levels of fluoride may cause dental fluorosis. One study reported

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[73] Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541–554.

[74] Agency for Toxic Substances and Disease Registry (ATSDR). 2008. Public Health Statement for Cadmium. CAS# 1306–19–0. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. Available on the Internet at *http://www.atsdr.cdc.gov/PHS/PHS.asp?id=46&tid=15.*

[75] Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Chlorine. Atlanta, GA: U.S. Department of Health and Human Services. *http://www.atsdr.cdc.gov/mmg/mmg.asp?id=198&tid=36.*

[76] U.S. EPA. 1987. Assessment of Health Risks to Garment Workers and Certain Home Residents from Exposure to Formaldehyde, Office of Pesticides and Toxic Substances, April 1987.

[77] International Agency for Research on Cancer (2006) Formaldehyde, 2–Butoxyethanol and 1-tert-Butoxypropan-2-ol. Monographs Volume 88. World Health Organization, Lyon, France.

[78] Agency for Toxic Substances and Disease Registry (ATSDR). 1999. Toxicological profile for Formaldehyde. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. *http://www.atsdr.cdc.gov/toxprofiles/tp111.html*

[79] WHO (2002) Concise International Chemical Assessment Document 40: Formaldehyde. Published under the joint sponsorship of the United Nations Environment Programme, the International Labour Organization, and the World Health Organization, and produced within the framework of the Inter-Organization Programme for the Sound Management of Chemicals. Geneva.

[80] Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Hydrogen Chloride. Atlanta, GA: U.S. Department of Health and Human Services. Available online at *http://www.atsdr.cdc.gov/mmg/mmg.asp?id=758&tid=147#bookmark02.*

[81] U.S. Environmental Protection Agency (U.S. EPA). 1995. Integrated Risk Information System File of Hydrogen Chloride. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at *http://www.epa.gov/iris/subst/0396.htm.*

menstrual irregularities in women occupationally exposed to fluoride via inhalation. The EPA has not classified HF for carcinogenicity.[82]

x. Lead

The main target for Pb toxicity is the nervous system, both in adults and children. Long-term exposure of adults to Pb at work has resulted in decreased performance in some tests that measure functions of the nervous system. Lead exposure may also cause weakness in fingers, wrists, or ankles. Lead exposure also causes small increases in blood pressure, particularly in middle-aged and older people. Lead exposure may also cause anemia.

Children are more sensitive to the health effects of Pb than adults. No safe blood Pb level in children has been determined. At lower levels of exposure, Pb can affect a child's mental and physical growth. Fetuses exposed to Pb in the womb may be born prematurely and have lower weights at birth. Exposure in the womb, in infancy, or in early childhood also may slow mental development and cause lower intelligence later in childhood. There is evidence that these effects may persist beyond childhood.[83]

There are insufficient data from epidemiologic studies alone to conclude that Pb causes cancer (is carcinogenic) in humans. DHHS has determined that Pb and Pb compounds are reasonably anticipated to be human carcinogens based on limited evidence from studies in humans and sufficient evidence from animal studies, and EPA has determined that Pb is a probable human carcinogen.

xi. Manganese

Health effects in humans have been associated with both deficiencies and excess intakes of Mn. Chronic exposure to high levels of Mn by inhalation in humans results primarily in central nervous system effects. Visual reaction time, hand steadiness, and eye-hand coordination were affected in chronically-exposed workers. Manganism, characterized by feelings of weakness and lethargy, tremors, a masklike face, and psychological disturbances, may result from chronic exposure to higher levels. Impotence and loss of libido have been noted in male workers afflicted with manganism attributed to inhalation exposures. The EPA has classified Mn in Group D, not classifiable as to carcinogenicity in humans.[84]

xii. Nickel

Respiratory effects have been reported in humans from inhalation exposure to Ni. No information is available regarding the reproductive or developmental effects of Ni in humans, but animal studies have reported such effects. Human and animal studies have reported an increased risk of lung and nasal cancers from exposure to Ni refinery dusts and nickel subsulfide. The EPA has classified nickel subsulfide as a human carcinogen and nickel carbonyl as a probable human carcinogen.[85] [86] The IARC has classified Ni compounds as carcinogenic to humans.[87]

xiii. Selenium

Acute exposure to elemental Se, hydrogen selenide, and selenium dioxide (SeO_2) by inhalation results primarily in respiratory effects, such as irritation of the mucous membranes, pulmonary edema, severe bronchitis, and bronchial pneumonia. One Se compound, selenium sulfide, is carcinogenic in animals exposed orally. EPA has classified elemental Se as a Group D, not classifiable as to human carcinogenicity, and selenium sulfide as a Group B2, probable human carcinogen.

b. Non-Hg HAP Emissions

Fossil-fuel fired boilers emit a variety of metal HAP, organic HAP and HAP that are acid gases. Acid gas and metal HAP emissions are discussed below.

i. Acid Gases

Based on the 2010 ICR and the National Air Toxics Assessment (NATA) inventory estimates of acid gas emissions, U.S. EGUs emit the majority of HCl and HF nationally, supporting EPA's view that it remains appropriate to regulate HAP from U.S. EGUs. Acid gas emissions from EGUs include HCl, HF, Cl_2, and HCN. These pollutants are emitted as a result of fluorine, chlorine, and nitrogen components of the fuels. Table 4 of this preamble shows emissions of certain acid gases from EGUs, based on the 2005 NATA inventory. 2010 estimates of emissions for acid HAP from U.S. EGU are 7,900 tpy for HCN, 106,000 tons for HCl, and 36,000 tons for HF.[88]

TABLE 4—SUMMARY OF ACID GAS EMISSIONS FROM EGU SOURCES

	2005 Acid HAP emissions from the National Air Toxics Assessment (NATA) (tpy)		Percent of total U.S. anthropogenic emissions in 2005
	U.S. EGU emissions	U.S. Non-EGU emissions	Non-EGU emissions
Hydrogen Cyanide[1]	1,200	14,000	8
Hydrogen Chloride	350,000	78,000	82
Hydrogen Fluoride	47,000	28,000	62

[1] Using cyanide emissions for HCN.

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[82] U.S. Environmental Protection Agency. Health Issue Assessment: Summary Review of Health Effects Associated with Hydrogen Fluoride and Related Compounds. EPA/600/8–89/002F. Environmental Criteria and Assessment Office, Office of Health and Environmental Assessment, Office of Research and Development, Cincinnati, OH. 1989.

[83] Agency for Toxic Substances and Disease Registry (ATSDR). 2007. Public Health Statement for Lead. CAS#: 7439–92–1. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. Available on the Internet at *http://www.atsdr.cdc.gov/ToxProfiles/phs13.html.*

[84] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Manganese. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1999.

[85] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Nickel Subsulfide. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1999.

[86] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Nickel Carbonyl. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1999.

[87] Nickel (IARC Summary & Evaluation, Volume 49, 1990), *http://www.inchem.org/documents/iarc/vol49/nickel.html.*

[88] We believe our estimate of the current level of acid HAP emissions based on the 2010 ICR database may underestimate total EGU acid HAP emissions due to targeting of the 2010 ICR on the best performing EGUs.

ii. Metal HAP

U.S. EGUs are the predominant source of emissions nationally for many metal HAP, including Sb, As, Cr, Co, and Se.

Metals are emitted primarily because they are present in fuels. Table 5 of this preamble shows selected metals emitted by EGUs and emission estimates based on data from the 2005 NATA inventory. 2010 estimates of metal HAP emissions are 25 tpy for antimony (Sb), 43 tpy for As, 2 tpy for Be, 3 tpy for Cd, 222 tpy for Cr, 19 tpy for Co, 183 tpy for Mn, 387 tpy for Ni, and 258 tpy for Se.[89] Depending on the metal, EGUs account for between 13 and 83 percent of national metal HAP emissions, and as a result it remains appropriate to regulate EGUs.

TABLE 5—SUMMARY OF METAL EMISSIONS FROM EGU SOURCES

	2005 Metal HAP emissions from the inventory used for the National Air Toxics Assessment (NATA) (tpy)		Percent of total U.S. anthropogenic emissions in 2005
	U.S. EGU emissions	U.S. Non-EGU emissions	
Antimony	19	83	19
Arsenic	200	120	62
Beryllium	10	13	44
Cadmium	25	38	39
Chromium	120	430	22
Cobalt	54	60	47
Manganese	270	1,800	13
Nickel	320	840	28
Selenium	580	120	83

3. Quantitative Risk Characterizations To Inform the Appropriate and Necessary Finding

EPA conducted quantitative risk analyses to evaluate the extent of risk posed by emissions of HAP from U.S. EGUs. These analyses demonstrate that U.S. EGU HAP emissions do create the potential for risks to the public health, as described below.

a. Scope of Quantitative Risk Analyses

To evaluate the potential for public health hazards from emissions of Hg and non-Hg HAP from U.S. EGUs, EPA conducted quantitative risk analyses using several methods intended to address specific risk-related questions.[90] [91] Outputs from this assessment include: (1) The potential exposures to MeHg and risks associated with current U.S. EGU Hg emissions for populations most likely to be at risk from exposure to MeHg associated with U.S. EGU Hg emissions; (2) excess deposition of Hg in nearby locations within 50 kilometers (km) of EGUs that might result in Hg deposition "hotspots"; (3) for populations living in the vicinity of EGUs, the maximum individual risks (MIR) associated with U.S. EGU non-Hg HAP emissions, for both cancer and non-cancer risks, compared to established health benchmarks (*e.g.,* greater than one in a million for cancer risks, and a HQ exceeding one for chronic non-cancer risks).[92]

To evaluate the potential for health risks associated with U.S. EGU Hg emissions, EPA conducted a national scale assessment of the impacts of U.S. EGU Hg emissions on exposures to MeHg above the RfD, and as a contributor to exposures above the RfD in conjunction with exposures from other U.S. and non-U.S. Hg emissions. To evaluate risks of U.S. EGU Hg "hotspots," EPA conducted a national scale assessment based on the Hg deposition modeling used in the national-scale Hg risk assessment. To evaluate inhalation risks of U.S. EGU non-Hg HAP emissions, EPA recently conducted 16 case studies at EGUs. EPA selected these case studies based on HAP emissions information from the ICR. For each case study, EPA estimated the MIR for cancer and non-cancer health effects for each HAP emitted by the case study U.S. EGU facility. Cancer risks for non-Hg HAP are estimated as the number of excess cancer cases per million people. This section briefly describes the methods used in the analyses and the results for the national-scale Hg risk analysis and the non-Hg HAP inhalation risk case studies.

b. Emissions for Hg and Non-Hg HAP

The national-scale Hg risk analysis is based on modeling Hg deposition associated with 2005 U.S. EGU Hg emissions and 2016 projected Hg emissions.

The 2005 base case includes 105 tons of Hg and 430,000 tons of HCl from all sources, of which 53 tons of Hg and 350,000 tons of HCl are from EGUs. The 2016 projected total Hg emissions from all sources used in the risk modeling are 64 tons and HCl emissions are 140,000 tons, with 29 tons of Hg and 74,000 tons of HCl from EGUs. U.S. EGU Hg emissions accounted for 50 percent of total U.S. Hg emissions in 2005 and are projected to account for 45 percent of such emissions in 2016. Details regarding the emissions used in these analyses are provided in the emissions memorandum, "Emissions Overview: Hazardous Air Pollutants in Support of the Proposed Toxics Rule".[93]

Between 2005 and 2010, Hg emissions in the U.S. have declined as a result of state regulations of Hg or Federal regulatory and enforcement actions that required installation of SO_2 scrubbers at EGUs which decreased Hg emissions.[94]

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[89] We believe our estimate of the current level of metal HAP emissions based on the 2010 ICR database may underestimate total EGU metal HAP emissions due to targeting of the 2010 ICR on the best performing EGUs.

[90] U.S. EPA. 2011. Technical Support Document: National-Scale Mercury Risk Assessment Supporting the Appropriate and Necessary Finding for Coal- and Oil-Fired Electric Generating Units. Office of Air Quality Planning and Standards.

[91] U.S. EPA. 2011. Technical Support Document: Non-Mercury HAP Case Studies Supporting the Appropriate and Necessary Finding for Coal- and Oil-Fired Electric Generating Units. Office of Air Quality Planning and Standards.

[92] The hazard quotient (HQ) is the estimated inhalation or ingestion exposure divided by the reference dose (RfD).

[93] Strum, M., Houyoux, M., op. cit., Section 4.

[94] The 2005 estimate is based on control configurations as of 2002, therefore it does not reflect reductions due to substantial control installations that took place between 2002 and 2005. The 2010 estimates reflect control

The 2010 ICR shows the EGU Hg and HCl totals are lower than in 2005, at 29 tons and 106,000 tons respectively.

Given that the 2010 emissions for Hg are much closer to the 2016 projected emissions than to the 2005 emissions, we focus on the results from 2016 from the national-scale Hg risk analysis described below, as the projected emissions are almost the same as current HAP emissions from EGUs.

c. National-Scale Hg Risk Modeling

i. Purpose and Scope of Analysis

The national-scale risk assessment for Hg focuses on risk associated with Hg released from U.S. EGUs that deposits to watersheds within the continental U.S., bioaccumulates in fish, and then is consumed as MeHg in fish eaten by subsistence fishers and other freshwater self-caught fish consumers. The risk assessment is intended to assess risk for scenarios representing high-end self-caught fish consumers active at inland freshwater lakes and streams. This reflects our goal of determining whether U.S. EGUs represent a potential public health hazard for the group of fish consumers likely to experience the highest risk attributable to U.S. EGUs. In defining the high fish consuming populations included in the analysis, we have used information from studies of fish consumption to ensure that we have identified fisher populations that are likely active to some extent across the watersheds included in this analysis (*i.e.,* they are not purely hypothetical). The risk assessment considered the magnitude and prevalence of the risk to public health posed by current U.S. EGU Hg emissions and the remaining risk posed by U.S. EGU Hg emissions after imposition of the requirements of the CAA, as described more fully below. In both cases, we assess the contribution of U.S. EGUs to potential risks from MeHg exposure relative to total MeHg risk associated with Hg deposited by other sources both domestic and international.

Risk from Hg exposures occurs primarily through the consumption of fish that have bioaccumulated MeHg originally deposited to watersheds following atmospheric release and transport. The population that is most at risk from consumption of MeHg in fish is children born to mothers who were exposed to MeHg during pregnancy through fish consumption. The type of fish consumption likely to lead to the greatest exposure to MeHg attributable to U.S. EGUs is associated with fishing activity at inland freshwater rivers and lakes located in regions with elevated U.S. EGU Hg deposition. Thus we focus on MeHg exposure to women of childbearing age who consume self-caught freshwater fish on a regular basis, *e.g.,* once a day to once every several days.

As noted above, current U.S. EGU Hg emissions as reflected in the 2010 ICR are closer to 2016 projected emissions than to the 2005 emissions. For this reason, in discussing risk estimates, we focus on the 2016 results rather than the 2005 results.

The risk assessment compares the U.S. EGU incremental contribution to total potential exposure with the RfD and also evaluates the percent of total Hg exposures from all sources contributed by U.S. EGUs (*i.e.,* the fraction of total risk associated with U.S. EGUs) to individual watersheds for which we have fish tissue MeHg data.

We used this information to assess whether a public health hazard is associated with U.S. EGU emissions. Our focus is on women of child-bearing age in subsistence fishing populations who consume freshwater fish that they or their family caught. These populations are likely to experience the greatest risk from Hg exposure when fishing at inland (freshwater) locations that receive the highest levels of U.S. EGU-attributable Hg deposition. We also acknowledge that additional populations are likely exposed to MeHg from consuming fish caught in near-coastal, *e.g.,* estuarine environments. However, there is high uncertainty about the relationship of MeHg levels in those fish and deposition of Hg from U.S. EGUs, and as such we have not included those types of fish consumption in our analysis. However, it is likely that the range of potential exposures to U.S. EGU Hg deposition across inland watersheds captures the types of potential exposures that occur in near-coastal environments, and, thus, likely represents potential risks from consumption of fish caught in those environments.

Consumption rates for the high-end fishing populations included in the risk assessment are based on studies in the published literature, and are documented in the TSD accompanying this finding.

We do not estimate risks associated with commercial fish consumption because of the expected low contribution of U.S. EGU Hg to this type of fish, relative to non-U.S. Hg emissions, and the high levels of uncertainty in mapping U.S. EGU Hg emissions to concentrations of MeHg in ocean-going fish. The population affected by those U.S. EGU Hg emissions that go into the global pool of Hg will potentially be much larger than the population of the U.S. Thus, the impacts of U.S. EGUs on global exposures to Hg, while highly uncertain, adds additional support to the finding that Hg emissions from U.S. EGUs pose a hazard to public health.

ii. Risk Characterization Framework

EPA assessed risk from potential exposure to MeHg through fish consumption at a subset of watersheds across the country for which we have measured fish tissue MeHg data. This risk assessment uses estimates of potential exposure for subsistence fisher populations to generate risk metrics based on comparisons of MeHg exposure to the reference dose. We are focusing on exposures above the RfD because it represents a sensitive risk metric that captures a wide range of neurobehavioral health effects. Reductions in exposure to MeHg are also expected to result in reductions in specific adverse effects including lost IQ points, and we discuss the risk analysis related to IQ loss in the National Scale Mercury Risk Assessment TSD.

For the analysis, we have developed a risk characterization framework for integrating two types of U.S. EGU-attributable risk estimates. This framework estimates the percent of watersheds where populations may be at risk due to potential exposures to MeHg attributable to U.S. EGU. The analysis is limited to those watersheds for which we have fish tissue MeHg samples, a total of approximately 2,400 out of 88,000 watersheds in the U.S. This total percent of watersheds includes ones that either have deposition of Hg from U.S. EGUs that is sufficient to lead to potential exposures that exceed the reference dose, even without considering the contributions from other U.S. and non-U.S. sources, or have deposition of Hg from U.S. EGUs that contributes at least 5 percent to total Hg deposition from all sources, in watersheds where potential exposures to MeHg from all sources (U.S. EGU, U.S. non-EGU, and non-U.S.) exceed the RfD.

This framework allows EPA to consider whether U.S. EGUs, evaluated without consideration of other sources, or in combination with other sources of Hg, pose a potential public health hazard.

iii. Analytical Approach

Several elements of this risk analysis including spatial scale, estimates of Hg deposition, estimates of fish tissue MeHg concentrations, estimates of fish consumptions rates, and calculation of

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information reported to EPA as part of the recent 2010 ICR in late 2009.

MeHg exposure are discussed in detail in the National Scale Mercury Risk Assessment TSD accompanying this finding, and are briefly summarized below.

Watersheds can be defined at varying levels of spatial resolution. For the purposes of this risk analysis, we have selected to use watersheds classified using 12-digit Hydrologic Unit Codes (HUC12),[95] representing a fairly refined level of spatial resolution with watersheds generally 5 to 10 km on a side, which is consistent with research on the relationship between changes in Hg deposition and changes in MeHg levels in aquatic biota.

After estimating total MeHg risk based on modeling consumption of fish at each of these watersheds, the ratio of U.S. EGU to total Hg deposition over each watershed (estimated using Community Multi-scale Air Quality modeling) is used to estimate the U.S. EGU-attributable fraction of total MeHg risk. This apportionment of total risk between the U.S. EGU fraction and the fraction associated with all other sources of Hg deposition is based on the EPA's Office of Water's Mercury Maps (MMaps) approach that establishes a proportional relationship between Hg deposition over a watershed and resulting fish tissue Hg levels, assuming a number of criteria are met.[96]

The fish tissue dataset for the risk assessment includes fish tissue Hg samples from the years 2000 to 2009, with samples distributed across 2,461 HUC12s. The samples are more heavily focused on locations east of the Mississippi River. The fish tissue samples come primarily from three sources: the National Listing of Fish Advisory (NLFA) database managed by EPA;[97] the U.S. Geologic Survey (USGS), which manages a compilation of Hg datasets as part of its Environmental Mercury Mapping and Analysis (EMMA) program, and EPA's National River and Stream Assessment (NRSA) study data. Most of the watersheds with measured fish tissue MeHg data had multiple measurements. This assessment used the 75th percentile fish tissue value at each watershed as the basis for exposure and risk characterization, based on the assumption that subsistence fishers would favor larger fish which have the potential for higher bioaccumulation. The use of the 75th percentile fish tissue MeHg value as the basis for risk characterization reflects our overall goal of modeling realistic high-end fishing behavior; in this case, reflecting individuals who target somewhat larger fish for purposes of supplementing their diets (the average fisher may eat a variety of different sized fish, but in order to capture higher potential MeHg exposure scenarios, it is realistic to assume that some fishers may favor somewhat larger fish).

Deposition of Hg for the continental U.S. was estimated using the Community Multiscale Air Quality model v4.7.1 (*http://www.cmaq-model.org*), applied at a 12 km grid resolution.

The CMAQ modeling was used to estimate total annual Hg deposition from U.S. and non-U.S. anthropogenic and natural sources over each watershed. In addition, CMAQ simulations were conducted where U.S. EGU Hg emissions were set to zero to determine the contribution of U.S. EGU Hg emissions to total Hg deposition. U.S. EGU-related Hg deposition characterized at the watershed-level for 2005 and 2016 is summarized in Table 6 of this preamble for the complete set of 88,000 HUC12 watersheds.

Table 6 is intended to demonstrate the wide variation across watersheds in the contribution of EGU emissions to deposition. The percentiles of total Hg deposition and U.S. EGU-attributable deposition are not linked, *e.g.,* the 99th percentile of the percent of total deposition attributable to U.S. EGUs is based on the distribution of total Hg deposition, and the 99th percentile of U.S. EGU-attributable Hg deposition is based on the distribution of U.S. EGU-attributable deposition. These percentiles do not occur at the same watershed.

TABLE 6—COMPARISON OF TOTAL AND U.S. EGU-ATTRIBUTABLE Hg DEPOSITION (μg/m²) FOR THE 2005 AND 2016 SCENARIOS *

Statistic	2005		2016	
	Total Hg deposition	U.S. EGU-attributable Hg deposition	Total Hg deposition	U.S. EGU-attributable Hg deposition
Mean	19.41	0.89	18.66	0.34
Median	17.25	0.24	16.59	0.15
75th percentile	23.69	1.07	22.83	0.46
90th percentile	30.78	2.38	29.90	0.85
95th percentile	36.85	3.60	35.16	1.18
99th percentile	58.32	7.77	56.23	2.41

* Statistics are based on CMAQ results interpolated to the watershed-level and are calculated using all ~88,000 watersheds in the U.S.

To give a better idea of the relationship between total deposition and U.S. EGU-attributable deposition, we also summarize the percent of total Hg deposition attributable to U.S. EGUs (by percentile) in Table 7. Table 7 shows the high variability in the percent contribution from U.S. EGU Hg emissions. Tables 6 and 7 cannot be directly compared, as the watershed with the 99th percentile U.S. EGU-attributable deposition is not the same watershed as the watershed with the 99th percentile U.S. EGU-attributable fraction of total Hg deposition. A watershed can have a high U.S. EGU-attributable fraction of total deposition and still have overall low Hg deposition.

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[95] U.S. Geological Survey and U.S. Department of Agriculture, Natural Resources Conservation Service, 2009, Federal guidelines, requirements, and procedures for the national Watershed Boundary Dataset: U.S. Geological Survey Techniques and Methods 11–A3, 55 p.

[96] Mercury Maps—A Quantitative Spatial Link Between Air Deposition and Fish Tissue Peer Reviewed Final Report. U.S. EPA, Office of Water, EPA–823–R–01–009, September, 2001.

[97] *http://water.epa.gov/scitech/swguidance/fishshellfish/fishadvisories/.*

TABLE 7—COMPARISON OF PERCENT OF TOTAL Hg DEPOSITION ATTRIBUTABLE TO U.S. EGUs FOR 2005 AND 2016 *

Statistic	2005 (percent)	2016 (percent)
Mean	5	2
Median	1	1
75th percentile	6	3
90th percentile	13	5
95th percentile	18	6
99th percentile	30	11

* Values are based on CMAQ results interpolated to the watershed-level and reflect trends across all ~88,000 watersheds in the U.S.

U.S. EGUs are estimated to contribute up to 30 percent of total Hg deposition in 2005 and up to 11 percent in 2016.

EPA estimates the relationship between the EGU-attributable Hg deposition and EGU-attributable fish tissue MeHg concentrations using an assumption of linear proportionality based on the agency's MMaps approach. The MMaps assumption specifies that, under certain conditions (*e.g.,* Hg air deposition is the primary source of Hg loading to a watershed and near steady-state conditions have been reached), a fractional change in Hg deposition to a watershed will ultimately be reflected in a matching proportional change in the levels of MeHg in fish.[98] [99] This assumption holds in watersheds where air deposition is the primary source of Hg loadings, and as a result, watersheds where this is not the case are removed from the risk analysis. The practical application of the MMaps approach is that U.S. EGUs will account for the same proportion of fish tissue MeHg in a watershed as they do for Hg deposition. MMaps is discussed in greater detail in section 1.3 and Appendix E of the National Scale Mercury Risk Assessment TSD. Patterns of U.S. EGU-attributable fish tissue MeHg concentrations are summarized in Table 8 of this preamble. Table 8 of this preamble compares total and U.S. EGU-attributable fish tissue MeHg concentrations for the 2005 and 2016 scenarios by watershed percentile.

TABLE 8—COMPARISON OF TOTAL AND U.S. EGU-ATTRIBUTABLE FISH TISSUE MeHg CONCENTRATIONS FOR 2005 AND 2016

Statistic	Fish tissue MeHg concentration (ppm)			
	2005		2016	
	Total	U.S. EGU-attributable	Total	U.S. EGU-attributable
Mean	0.31	0.024	0.29	0.008
50th Percentile	0.23	0.014	0.20	0.005
75th Percentile	0.39	0.032	0.36	0.011
90th Percentile	0.67	0.056	0.63	0.019
95th Percentile	0.91	0.079	0.87	0.026
99th Percentile	1.34	0.150	1.29	0.047

Because the focus of this analysis is on higher-consumption self-caught fisher populations active at inland freshwater locations, we identified surveys of higher consumption fishing populations active at inland freshwater rivers and lakes within the continental U.S. to inform the selection of consumption rate scenarios.[100]

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[98] The MMaps approach implements a simplified form of the IEM–2M model applied in EPA's Mercury Study Report to Congress (Mercury Maps—A Quantitative Spatial Link Between Air Deposition and Fish Tissue Peer Reviewed Final Report. U.S. EPA, Office of Water, EPA–823–R–01–009, September, 2001). By simplifying the assumptions inherent in the freshwater ecosystem models that were described in the Report to Congress, the MMaps model showed that these models converge at a steady-state solution for MeHg concentrations in fish that are proportional to changes in Hg inputs from atmospheric deposition (*e.g.,* over the long term fish concentrations are expected to decline proportionally to declines in atmospheric loading to a watershed). This solution only applies to situations where air deposition is the only significant source of Hg to a water body, and the physical, chemical, and biological characteristics of the ecosystem remain constant over time. EPA recognizes that concentrations of MeHg in fish across all ecosystems may not reach steady state and that ecosystem conditions affecting Hg dynamics are unlikely to remain constant over time. EPA further recognizes that many water bodies, particularly in areas of historic gold and Hg mining in western states, contain significant non-air sources of Hg (note, however, that as described below, we have excluded those watersheds containing gold mines or with other non-EGU related anthropogenic Hg releases exceeding specified thresholds).

[99] The risk assessment is not designed to track the detailed temporal profile associated with changes in fish tissue MeHg levels following changes in Hg deposition. Rather, we are focusing on estimating risk in the future, assuming that near steady state conditions have been reached (following a simulated change in Hg deposition). Additional detail regarding the temporal profile issue and other related factors (*e.g.,* methylation potential across watersheds) is discussed in Section 1.3 and in Appendix E of the National Scale Mercury Risk Assessment TSD).

[100] A number of criteria had to be met for a study to be used in providing explicit consumption rates for the high-end fisher populations of interest in this analysis. For example, studies had to provide estimates of self-caught fish consumption and not conflate these estimates with consumption of commercially purchased fish. Furthermore, these studies had to focus on freshwater fishing activity, or at least have the potential to reflect significant contributions from that category, such that the fish consumption rates provided in a study could be reasonably applied in assessing freshwater fishing activity. Studies also had to provide statistical estimates of fish consumptions (*i.e.,* means, medians, 90th percentiles, *etc*). Given our interest in higher-end consumption rates, the studies also had to either provide upper percentile estimates, or support the derivation of those estimates (*e.g.,* provide medians and a standard deviations). Studies of activity at specific watersheds (*e.g.,* creel surveys), while informative in supporting the presence of higher-end consumption rates, could not be used as the basis for defining our high-end consumption rates since there would be greater uncertainty in extrapolating activity at a specific river or lake more broadly to fishing populations in a region. Therefore, we focused on studies characterizing fishing activity more broadly than at a specific fishing location.

Information on the studies used to develop the high end fish consumption scenarios for the risk analysis is provided in the National Scale Mercury Risk Assessment TSD.

Generally all of the studies identified high-end percentile consumption rates (90th to 99th percentiles for the populations surveyed) ranging from approximately one fish meal every few days to a fish meal a day (*i.e.,* 120 grams per day (g/day) to greater than 500 g/day fish consumption). We used this trend across the studies to support application of a generalized female high-end fish consumption scenario (high-end female consumer scenario) across most of the 2,461 watersheds.[101]

iv. Risk Related to Exposure to MeHg in Fish and Assessment of Contribution of U.S. EGUs to MeHg Exposure and Risk

For the scenario representing high-end female fish consumption, we estimated total exposure to MeHg at each of the 2,461 watersheds.[102] Estimates of total Hg exposure were generated by combining 75th percentile fish tissue values with the consumption rates for female subsistence fishers. A cooking loss factor (reflecting the fact that the preparation of fish can result in increased Hg concentrations) was also included in exposure calculations.[103]

Our estimates of total percent of watersheds where female subsistence fishing populations may be at risk from exposure to U.S. EGU-attributable MeHg are as high as 28 percent. The upper end estimate of 28 percent of watersheds reflects the 99th percentile fish consumption rate for that population, and a benchmark of 5 percent U.S. EGU contribution to total Hg deposition in the watershed. Any contribution of Hg emissions from EGUs to watersheds where potential exposures from total Hg deposition exceed the RfD is a hazard to public health, but for purposes of our analyses we evaluated only those watersheds where we determined EGUs contributed 5 percent or more to deposition to the watershed. EPA believes this is a conservative approach given the increasing risks associated with incremental exposures above the RfD. Of the total number of watersheds where populations may be at risk from exposure to EGU-attributable MeHg, we estimate that up to 22 percent of watersheds included in this analysis could potentially have populations at risk based on consideration of the U.S. EGU attributable fraction (*e.g.,* 5, 10, 15, or 20 percent) of total Hg deposition over watersheds with total risk judged to represent a public health hazard (MeHg total exposure greater than the RfD).[104] Of the total number of watersheds where populations may be at risk from exposures to U.S. EGU-attributable MeHg, we estimate that up to 12 percent of watersheds included in this analysis could potentially have populations at risk because the U.S. EGU incremental contribution to exposure is above the RfD, even before consideration of contributions to exposures from U.S. non-EGU and non-U.S. sources. In other words, for this 12 percent of watersheds, even if there were no other sources of Hg exposure, exposures associated with deposition attributable to U.S. EGUs would place female high-end consumers above the MeHg RfD. The upper end estimate of 12 percent of watersheds reflects a scenario using the 99th percentile fish consumption rate.

The two estimates of percent of watersheds where populations may be at risk from EGU-attributable Hg do not sum to the total estimates of 28 percent because some watersheds where U.S. EGUs contribute greater than 5 percent to total Hg deposition also have U.S. EGU attributable exposures that exceed the RfD without consideration of exposures from other U.S. and non-U.S. Hg sources.

Exposures based on the 99th percentile consumption rate represent close to maximum potential individual risk estimates. These consumption rates are based on data reported by fishers in surveys, and, thus, represent actual consumption rates in U.S. populations. There are also a number of case studies in other locations, such as poor urban areas, which provide additional evidence that high fish consumption occurs in a number of locations throughout the U.S.[105] [106] [107] [108] However, EPA does not have sufficiently complete data on the specific locations where these high self-caught fish consuming populations reside and fish, and as a result, there is increased uncertainty about the prevalence of populations who are high-end consumers of fish caught in the set of watersheds included in the analysis. Populations matching the high-end fish consumption scenario could be restricted to a subset of these watersheds, or could be more heavily focused at watersheds with higher or lower U.S. EGU-attributable fish tissue MeHg (and consequently higher or lower U.S. EGU-attributable risk).

With regard to the other fisher populations included in the full risk assessment described in the TSD (Vietnamese, Laotians, Hispanics, blacks and whites in the southeast, and tribes in the vicinity of the Great Lakes), our risk estimates suggests that the high-end female consumer assessed at the national-level generally provides coverage (in terms of magnitude of risk) for all of these fisher populations except blacks and whites in the southeast.[109] [110]

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[101] Reflecting the fact that higher levels of self-caught fish consumption (approaching subsistence) have been associated with poorer populations, we only assessed this generalized high-end female consumer scenario at those watersheds located in U.S. Census tracts with at least 25 individuals living below the poverty line (this included the vast majority of the 2,461 watersheds and only a handful were excluded due to this criterion).

[102] As noted earlier, each high-end fish consuming female population included in the analysis was assessed for a subset of these watersheds, depending on which of those watersheds intersected a U.S. Census tract containing a "source population" for that fish consuming population. Of the populations assessed, the low-income female subsistence fishing population scenario was assessed for the largest portion (2,366) of the 2,461 watersheds.

[103] Morgan, J.N., M.R. Berry, and R.L. Graves. 1997. "Effects of Commonly Used Cooking Practices on Total Mercury Concentration in Fish and Their Impact on Exposure Assessments." Journal of Exposure Analysis and Environmental Epidemiology 7(1):119–133.

[104] Because of the MMaps assumption of linear proportionality between deposition and exposures, a 5 percent U.S. EGU contribution to deposition will produce an equivalent 5 percent U.S. EGU contribution to MeHg exposures.

[105] Burger, J., K. Pflugh, L. Lurig, L. Von Hagen, and S. Von Hagen. 1999. Fishing in Urban New Jersey: Ethnicity Affects Information Sources, Perception, and Compliance. Risk Analysis 19(2): 217–229.

[106] Burger, J., Stephens, W., Boring, C., Kuklinski, M., Gibbons, W.J., & Gochfield, M. (1999). Factors in exposure assessment: Ethnic and socioeconomic differences in fishing and consumption of fish caught along the Savannah River. Risk Analysis, 19(3).

[107] Chemicals in Fish Report No. 1: Consumption of Fish and Shellfish in California and the United States Final Draft Report. Pesticide and Environmental Toxicology Section, Office of Environmental Health Hazard Assessment, California Environmental Protection Agency, July 1997.

[108] Corburn, J. (2002). Combining community-based research and local knowledge to confront asthma and subsistence-fishing hazards in Greenpoint/Williamsburg, Brooklyn, New York. Environmental Health Perspectives, 110(2).

[109] Specifically, upper percentile risk estimates for the high-end female consumer assessed at the national level were notably higher than matching percentile estimates for the Hmong, Vietnamese, Hispanic, and Tribal populations. By contrast, risk estimates for whites in the southeast were somewhat higher than the high-end female consumer, while risk estimates for blacks in the southeast were notably higher (see summary of risk estimates in the TSD supporting this finding).

[110] The National Scale Mercury Risk Assessment TSD discusses the greater uncertainty in characterizing the magnitude of high-end fish consumption for these specialized populations due, in particular, to the lower sample sizes associated with the survey data (see Appendix C, Table C–1).

v. Variability and Uncertainty (Including Discussion of Sensitivity Analyses)

There are some uncertainties in EPA's analyses which could lead to under or over prediction of risk to public health from U.S. EGU Hg emissions. Based on sensitivity analyses we have conducted, we conclude that even under different assumptions about the applicability of the MMaps proportionality assumption, Hg from U.S. EGUs constitutes a hazard to public health due to the percent of watersheds where U.S. EGUs cause or contribute to exposures to MeHg above the RfD.

Key sources of uncertainty potentially impacting the risk analysis include: (1) Uncertainty in predicting Hg deposition over watersheds using CMAQ; (2) uncertainty in predicting which watersheds will be subject to high-end fishing activity and the nature of that activity (*e.g.,* frequency of repeated activity at a given watershed and the types/sizes of fish caught); (3) uncertainty in using MMaps to apportion exposure and risk between different sources, including U.S. EGUs, and predicting changes in fish tissue MeHg levels for future scenarios; and (4) potential under-representation of watersheds highly impacted by U.S.-attributable Hg deposition due to limited MeHg sampling. In the National Scale Mercury Risk Assessment TSD, we describe in greater detail key sources of uncertainty impacting the risk analysis, including their potential impact on the risk estimates and the degree to which their potential impact is characterized as part of the analysis.

As part of the analysis, we have also completed a number of sensitivity analyses focused on exploring the impact of uncertainty related to the application of the MMaps approach in apportioning exposure and risk estimates between sources (U.S. EGU and total) and in predicting changes in fish tissue MeHg levels.[111] These sensitivity analyses evaluated: (1) The effect of including watersheds that may be disproportionately impacted by non-air Hg sources;[112] and (2) the representativeness of the MMaps approach, which was tested for lakes, when applied to streams and rivers (in the analysis, the MMaps was applied to watersheds including a mixture of streams, rivers, and lakes). The results of the limited sensitivity analyses we were able to conduct suggest that uncertainties due to application of MMaps would not affect our finding that U.S. EGU-attributable Hg deposition poses a hazard to public health.

We also examined the potential for under-representation of watersheds highly impacted by U.S.-attributable Hg deposition due to limited MeHg sampling, by identifying watersheds that did not have fish tissue MeHg samples, but had U.S. EGU-attributable Hg deposition at least as high as watersheds that were identified as being at risk of potential exposures greater than the RfD. Comparing the pattern of U.S. EGU-attributable Hg deposition across all watersheds with that for watersheds containing fish tissue MeHg data shows that while we have some degree of coverage for watersheds with high U.S. EGU-attributable deposition, this coverage is limited, especially in areas of Pennsylvania which have high levels of U.S. EGU-attributable deposition. For this reason, we believe that the actual number of watersheds where populations may be at risk from exposures to U.S. EGU-attributable MeHg could be substantially larger than the number estimated based on the available fish tissue MeHg sampling data.

d. U.S. EGU Case Studies of Cancer and Non-Cancer Inhalation Risks for Non-Hg HAP

EPA conducted 16 case studies to estimate the potential for human health impacts from current emissions of HAP other than Hg from EGUs. A refined chronic inhalation risk assessment was performed for each case study facility. The results of this analysis were that 4 (out of 16) facilities posed a lifetime cancer risk of greater than 1 in 1 million (the maximum was 10 in 1 million) and 3 more posed a risk at 1 in 1 million. Risk was driven by Ni (the oil-fired unit) and Cr^{+6} (the coal-fired units).

i. Case Study Selection

An initial set of eight case study facilities was selected based on several factors. First, we considered facilities with the highest estimated cancer and non-cancer risks using the 2005 National Emissions Inventory (NEI) data and the Human Exposure Model (HEM). The 2005 NEI data were used because the initial set of case study facilities was selected before we received the bulk of the emissions data from the 2010 ICR. Other factors considered in the selection included whether facilities had implemented emission control measures since 2005, and their proximity to residential areas. After the receipt of more data through the 2010 ICR, additional case study facilities were selected, based on the magnitude of emissions, heat input values (throughput), and level of emission control. There were a total of 16 case study facilities, 15 that use coal as fuel, and 1 that uses oil.

ii. Methods

Annual emissions estimates for each EGU (including those in the initial set of case study facilities) were developed using data from the 2010 ICR. The results for the initial set indicated that Ni, Cr^{+6}, and As were the cancer risk drivers, and that non-cancer risks did not produce any hazard index (HI) estimates exceeding one. Although the non-cancer risks were low (the maximum chronic noncancer HI was 0.4), they were driven by emissions of Ni, As, and HCl. For the reasons discussed above, emissions were estimated only for Ni, Cr^{+6}, and As for the additional case study facilities. Additional details on the emissions used in the modeling are provided in a supporting memorandum to the docket for this action (Non-Hg Case Study Chronic Inhalation Risk Assessment for the Utility MACT "Appropriate and Necessary" Analysis) (Non-Hg Memo). For each of the 16 case study facilities, we conducted refined dispersion modeling with EPA's AERMOD modeling system (U.S. EPA, 2004) to calculate annual ambient concentrations. Average annual concentrations were calculated at census block centroids.

We calculated the MIR for each facility as the cancer risk associated with a continuous lifetime (24 hours per day, 7 days per week, and 52 weeks per year for a 70-year period) exposure to the maximum concentration at the centroid of an inhabited census block, based on application of the unit risk estimate from EPA's IRIS, which is a human health assessment program that evaluates quantitative and qualitative risk information on effects that may result from exposure to environmental contaminants. For Ni compounds, we

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[111] The sensitivity analyses completed for the risk assessment focused on assessing sources of uncertainty associated with the application of the MMaps approach, because this was a critical element in the risk assessment and identified early on as a key source of potential uncertainty. Given the schedule of the analysis, we did not have time to complete a full influence analysis to identify those additional modeling elements that might introduce significant uncertainty and therefore should be included in a sensitivity analysis. Appendix F, Table F–2 of the Mercury Risk TSD provides a qualitative discussion of key sources of uncertainty and their potential impact on the risk assessment.

[112] In addition to non-air Hg sources of loadings, some regions of concern may also have longer lag period associated with the linkage between Hg deposition such that the fish tissue MeHg levels we are using are actually associated with older historical Hg deposition patterns.

used 65 percent of the IRIS URE for nickel subsulfide. The determination of this value is discussed in the Non-Hg Memo, and the value is receiving peer review as discussed in section later. To assess the risk of non-cancer health effects from chronic exposures, following the approach recommended in EPA's Mixtures Guidelines,[113] [114] we summed the HQs for all HAP that affect a common target organ system to obtain the HI for that target organ system (target-organ-specific HI, or TOSHI). The HQ for chronic exposures is the estimated chronic exposure (again, based on the estimated annual average ambient concentration at each nearby census block centroid) divided by the chronic non-cancer reference level, which is usually the EPA reference concentration (RfC). In cases where an IRIS RfC is not available, EPA utilizes the following prioritized sources for chronic dose-response values: (1) The Agency for Toxic Substances and Disease Registry (ATSDR) Minimum Risk Level (MRL), and (2) the California Environmental Protection Agency chronic Reference Exposure Level (REL). In this assessment, we used the IRIS RfC values for Cr^{+6} and HCl, the ATSDR MRL for Ni compounds, and the California Environmental Protection Agency REL for As.

iii. Results

The highest estimated lifetime cancer risk from any of the 16 case study facilities was 10 in 1 million (1×10^{-5}), driven by Ni emissions from the 1 case study facility with oil-fired units. For the facilities with coal-fired units, there were 3 with maximum cancer risks greater than 1 in 1 million (the highest was 8 in 1 million), all driven by Cr^{+6}, and there were 4 with maximum cancer risks at 1 in 1 million. All of the facilities had non-cancer TOSHI values less than one, with a maximum HI value of 0.4 (also driven by Ni emissions from the one case study facility with oil-fired units). The maximum chronic impacts of HCl emissions were all less than 10 percent of its chronic RfC. Because of uncertainties in their emission rates, other acid gases (Cl_2, HF, and HCN) were not included in the assessment of noncancer impacts. Because EGUs are not generally co-located with other source categories, facility-wide HAP emissions and risks are equal to those associated with the EGU source category.

The cancer risk estimates from this assessment indicate that the EGU source category is not eligible for delisting under CAA section 112(c)(9)(B)(i), which specifies that a category may be delisted only when the Administrator determines "* * * that no source in the category (or group of sources in the case of area sources) emits such HAP in quantities which may cause a lifetime risk of cancer greater than one in one million to the individual in the population who is most exposed to emissions of such pollutants from the source * * *" We note that, because these case studies do not cover all facilities in the category, and because our assessment does not include the potential for impacts from different EGU facilities to overlap one another (*i.e.,* these case studies only look at facilities in isolation), the maximum risk estimates from the case studies may underestimate true maximum risks.

e. Peer-Review of Quantitative Risk Analyses

The Agency has determined that the National-Scale Mercury Risk Analysis supporting EPA's 2011 review of U.S. EGU health impacts should be peer-reviewed. In addition, the Agency has determined that the characterization of the chemical speciation for the emissions of Cr and Ni should be peer-reviewed. The Agency has evaluated the other components of the analyses supporting this finding and determined that the remaining aspects of the case study analyses for non-Hg HAP use methods that have already been subject to adequate peer-review. As a result, the Agency is limiting the peer-review to the National-Scale Mercury Risk Analysis and the speciation of emissions for Cr and Ni. Due to the court-ordered schedule for this proposed rule, EPA will conduct these peer reviews as expeditiously as possible after issuance of this proposed rule and will publish the results of the peer reviews and any EPA response to them before the final rule.

4. Qualitative Assessment of Potential Environmental Risks From Exposures of Ecosystems Through Hg and Non-Hg HAP Deposition

Adverse effects on fish and wildlife have been observed to be occurring today which are the result of elevated exposures to MeHg, although these effects have not been quantitatively assessed.

Elevated MeHg concentrations in fish and wildlife can occur not only in areas of high Hg deposition. Elevated MeHg concentrations can also occur in diverse locations, including watersheds that receive average or even relatively low Hg deposition, but are particularly sensitive to Hg pollution, for example, they have higher than average methylation rates due to high levels of sulfur deposition. Such locations are characterized by moderate deposition levels that have generated high Hg concentrations in biota compared to the surrounding landscape receiving a similar Hg loading. These Hg-sensitive watersheds readily transport inorganic Hg, convert the inorganic Hg to MeHg, and bioaccumulate this MeHg through the food web. Areas of enhanced MeHg in fish and wildlife are not constrained to a single Hg source, because ecosystems respond to the combined effects of Hg pollution from multiple sources.

A review of the literature on effects of Hg on reproduction in fish[115] reports adverse reproductive effects for numerous species including trout, bass (large and smallmouth), northern pike, carp, walleye, salmon, and others from laboratory and field studies. Mercury also affects avian species. In previous reports [116] much of the focus has been on large fish-eating species, in particular the common loon. Breeding loons experience significant adverse effects including behavioral (reduced nest-sitting), physiological (flight feather asymmetry) and reproductive (chicks fledged/territorial pair) effects.[117]

Other fish-eating bird species such as the white ibis and great snowy egret experience a range of adverse effects due to exposure to Hg. The white ibis has been observed to have decreased foraging efficiency [118] and decreased

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[113] U.S. EPA, 1986, Guidelines for the Health Risk Assessment of Chemical Mixtures, EPA–630–R–98–002. *http://www.epa.gov/NCEA/raf/pdfs/chem_mix/chemmix_1986.pdf.*

[114] U.S. EPA, 2000. Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures. EPA–630/R–00–002. *http://www.epa.gov/ncea/raf/pdfs/chem_mix/chem_mix_08_2001.pdf.*

[115] Crump, Kate L., and Trudeau, Vance L. Mercury-induced reproductive impairment in fish. Environmental Toxicology and Chemistry. Vol. 28, No. 5, 2009.

[116] U.S. Environmental Protection Agency (EPA). 1997. Mercury Study Report to Congress. Volume V: Health Effects of Mercury and Mercury Compounds. EPA–452/R–97–007. U.S. EPA Office of Air Quality Planning and Standards, and Office of Research and Development.

U.S. Environmental Protection Agency (U.S. EPA). 2005. *Regulatory Impact Analysis of the Final Clean Air Mercury Rule.* Office of Air Quality Planning and Standards, Research Triangle Park, NC., March; EPA report no. EPA–452/R–05–003. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/mercury_ria_final.pdf.*

[117] Evers, David C., Savoy, Lucas J., DeSorbo, Christopher R., Yates, David E., Hanson, William, Taylor, Kate M., Siegel, Lori S., Cooley, John H. Jr., Bank, Michael S., Major, Andrew, Munney, Kenneth, Mower, Barry F., Vogel, Harry S., Schoch, Nina, Pokras, Mark, Goodale, Morgan W., Fair, Jeff. Adverse effects from environmental mercury loads on breeding common loons. Ecotoxicology. 17:69–81, 2008.

[118] Adams, Evan M., and Frederick, Peter C. Effects of methylmercury and spatial complexity on foraging behavior and foraging efficiency in juvenile

reproductive success and altered pair behavior.[119] These effects include significantly more unproductive nests, male/male pairing, reduced courtship behavior and lower nestling production by exposed males. In egrets, Hg has been implicated in the decline of the species in south Florida [120] and studies show liver and possibly kidney effects.[121] Insectivorous birds have also been shown to suffer adverse effects due to Hg exposure. Songbirds such as Bicknell's thrush, tree swallows and the great tit have shown reduced reproduction, survival, and changes in singing behavior. Exposed tree swallows produced fewer fledglings,[122] lower survival,[123] and had compromised immune competence.[124] The great tit has exhibited reduced singing behavior and smaller song repertoire in areas of high contamination.[125]

In mammals, adverse effects from Hg including mortality have been observed in mink and river otter, both fish eating species. Other adverse effects may include increased activity, poorer maze performance, abnormal startle reflex, and impaired escape and avoidance behavior.[126] EPA is also concerned about the potential impacts of HCl and other acid gas emissions on the environment. When HCl gas encounters water in the atmosphere, it forms an acidic solution of hydrochloric acid. In areas where the deposition of acids derived from emissions of sulfur and NO_X are causing aquatic and/or terrestrial acidification, with accompanying ecological impacts, the deposition of hydrochloric acid would further exacerbate these impacts. Recent research[127] has, in fact, determined that deposition of airborne HCl has had a greater impact on ecosystem acidification than anyone had previously thought, although direct quantification of these impacts remains an uncertain process.

5. Potential for Deposition "Hotspots" in Areas Near U.S. EGUs

Although it has been characterized and addressed as a global issue, Hg from U.S. EGUs is shown to deposit in higher quantities close to emission sources, and around some sources can be as high as 3 times the regional average deposition. EPA evaluated the potential for "hot spot" deposition near U.S. EGU emission sources on a national scale, based on the CMAQ modeled Hg deposition for 2005 and 2016.[128] We calculated the excess deposition within 50 km of U.S. EGU sources by first calculating the average U.S. EGU attributable Hg deposition within a 500 km radius around the U.S. EGU source. This deposition represents the likely regional contribution around the EGU. We then calculated the average U.S. EGU attributable Hg deposition within 50 km of the U.S. EGUs to characterize local deposition plus regional deposition near the EGU facility. Excess local deposition is then the 50 km radius average deposition minus the 500 km radius average deposition. Summary statistics for the excess local deposition are provided in Table 9 of this preamble. Table 9 of this preamble shows both the mean excess deposition around all U.S. EGUs, and the mean excess deposition around just the top 10 percent of Hg emitting U.S. EGUs. Table 9 of this preamble also shows the excess Hg deposition as a percent of the average regional deposition to provide context for the magnitude of the local excess deposition. In 2005, for all U.S. EGU, the excess was around 120 percent of the average deposition, while for the top 10 percent of Hg emitting U.S. EGU, local deposition was around 3.5 times the regional average. By 2016, although the absolute excess deposition falls, the local excess still remains around 3 times the regional average for the highest 10 percent of Hg emitting U.S. EGUs.

TABLE 9—EXCESS LOCAL DEPOSITION OF Hg BASED ON 2005 CMAQ MODELED Hg DEPOSITION

	50 km-Radius-average excess local deposition values (μg/m²)	
	Mean across EGUs (percent of regional average deposition)	
	2005	2016
All U.S. EGU sites with Hg emissions > 0 (672 sites)	1.65 (119%)	0.36 (93%)
Top ten percent U.S. EGU in Hg emissions (67 sites)	4.89 (352%)	1.18 (302%)

This analysis shows that there is excess deposition of Hg in the local areas around EGUs, especially those with high Hg emissions. Although this is not necessarily indicative of higher risk of adverse effects from consumption of MeHg contaminated fish from waterbodies around the U.S. EGUs, it does indicate an increased chance that Hg from U.S. EGUs will impact local waterbodies around the EGU sources, and not just impact regional deposition.

6. Emissions Controls for Emissions of Hg and Non-Hg HAP Are Available and Effective

Analyses of currently available control technologies for Hg, acid gases,

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white ibises (Eudocimus albus). Environmental Toxicology and Chemistry. Vol 27, No. 8, 2008.

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[128] More details are provided in the National Scale Mercury Risk Assessment TSD.

and non-Hg metal HAP show that significant reductions in these pollutants can be achieved from EGUs with significant coincidental reductions in the emissions of other pollutants as well.

a. Availability of Hg Emissions Control Options

The control of Hg in a coal combustion flue gas is highly dependent upon the form (or species) of the Hg. The Hg can be present in one of three forms: as Hg^0, as a vapor of Hg^{+2} (*e.g.,* mercuric chloride, $Hg(Cl_2)$), or as Hg_P (*e.g.,* adsorbed on fly ash or unburned carbon). The specific form of the Hg in the flue gas will strongly influence the effectiveness of available control technology for Hg control. The form (or "speciation") of the Hg is determined by the flue gas chemistry and by the time-temperature profile in the post combustion environment. During coal combustion, Hg is released into the exhaust gas as Hg^0. This vapor may then continue through the flue gas cleaning equipment and exit the stack as gaseous Hg^0 or it may be oxidized to Hg^{+2} compounds (such as $HgCl_2$) via homogeneous (gas-gas) or heterogeneous (gas-solid) reactions. The primary homogeneous oxidation mechanism is the reaction with gas-phase chlorine (Cl radical or possibly, HCl) to form $HgCl_2$. Although this mechanism is thermodynamically favorable, it is thought to be kinetically limited due to rapid cooling of the flue gas stream. Heterogeneous oxidation reactions occur on the surface of fly ash and unburned carbon. It is thought that in-duct chlorination of the surface of the fly ash, unburned carbon, or injected activated carbon sorbent is the first step to heterogeneous oxidation and surface binding of vapor-phase Hg^0 in the flue gas stream (i.e., the formation of Hg_P).

Mercury control can occur as a "co-benefit" of conventional control technologies that have been installed for other purposes. Particulate Hg can be effectively removed along with other flue gas PM (including non-Hg metal HAP) in the primary or secondary PM control device. For units using electrostatic precipitators (ESPs), the effectiveness will depend upon the amount of Hg_P entering the ESP. Units that burn coals with higher levels of native chlorine and that produce more unburned carbon can see good Hg removal in the ESP. Fabric filters (FF) have been shown to provide very high levels of control when there is adequate halogen to convert the Hg to the oxidized form. Units with wet FGD scrubbers can achieve high levels of Hg control—provided that the Hg is present in the oxidized (*i.e.,* the soluble) form. A selective catalytic reduction (SCR) catalyst can enhance the Hg removal by catalytically converting Hg^0 to Hg^{+2}, making it more soluble and more likely to be captured in the scrubber solution. Halogen additives (usually bromide salts, but chloride salts may also be used) can also be added directly to the coal or injected into the boiler to enhance the oxidation of Hg.

Activated carbon injection (ACI) is the most successfully demonstrated Hg-specific control technology. In this case, a powdered AC sorbent is injected into the duct upstream of the primary or a secondary PM control device. The carbon is injected to maximize contact with the flue gas. Mercury binds on the surface of the carbon to form Hg_P, which is then removed in the PM control device. Conventional (*i.e.,* non-halogenated) AC is effective when capturing Hg that is already predominantly in the oxidized state or when there is sufficient flue gas halogens to promote oxidation of the Hg on the AC surface. Pre-halogenated (*i.e.,* brominated) AC has been shown to be very effective when used in combination with low chlorine coals (such as U.S. western subbituminous coals). Activated carbons can suffer from poor performance when used with high sulfur coals. Firing high sulfur coals (especially when an SCR is also used) can result in sulfur trioxide (SO_3) vapor in the flue gas stream. The SO_3 competes with Hg for binding sites on the surface of the AC (or unburned carbon) and limits the effectiveness of the injected AC. An SO_3 mitigation technology—such as dry sorbent injection (DSI, *e.g.,* trona or hydrated lime)—applied upstream of the ACI can minimize this effect.

Mingling of AC with the fly ash can affect the viability for use of the captured fly ash as an additive in concrete production. Use of the TOXECON™ configuration can keep the fly ash and the AC separate. This configuration consists of the primary PM control device (ESP or FF) followed by a secondary downstream pulsejet FF. The AC is injected prior to the secondary FF. The fly ash is captured in the primary PM control device and the AC and Hg are captured in the downstream secondary FF.

b. Availability of PM or Metal HAP Emissions Control Options

Electrostatic precipitators and FFs are the most commonly applied PM control technologies in U.S. coal-fired EGUs. Newer units have tended to install FFs, which usually provide better performance than ESPs. An existing facility that wants to upgrade the PM control may choose to replace the current equipment with newer, better performing equipment. The facility may also consider installation of a downstream secondary PM control device—such as a secondary FF. A wet ESP (WESP) can be installed downstream of a wet FGD scrubber for control of condensable PM.

c. Availability of Acid Gas Emissions Control Options

Acid gases are likely to be removed in typical FGD systems due to their solubility or their acidity (or both). The acid-gas HAP—HCl, HF, and HCN (representing the "cyanide compounds")—are water-soluble compounds, more soluble in water than is SO_2. This indicates that HCl, HF, and HCN should be more easily removed from a flue gas stream in a typical FGD system than will SO_2, even when only plain water is used. Hydrogen chloride is also a strong acid and will react easily in acid-base reactions with the caustic sorbents (*e.g.,* lime, limestone) that are commonly used in FGD systems. Hydrogen fluoride is a weaker acid, having a similar acid dissociation constant as that of SO_2. Cyanide is the weakest of these acid gases. In the slurry streams, composed of water and sorbent (*e.g.,* lime, limestone) used in both wet-scrubber and dry spray dryer absorber FGD systems, acid gases and SO_2 are absorbed by the slurry mixture and react to form alkaline salts. In fluidized bed combustion (FBC) systems, the acid gases and SO_2 are adsorbed by the sorbent (usually limestone) that is added to the coal and an inert material (*e.g.,* sand, silica, alumina, or ash) as part of the FBC process. Hydrogen chloride and HF have also been shown to be effectively removed using DSI where a dry, alkaline sorbent (*e.g.,* hydrated lime, trona, sodium carbonate) is injected upstream of a PM control device. Chlorine in the fuel coal may also partition in small amounts to Cl_2. This is normally a very small fraction relative to the formation of HCl. Limited testing has shown that Cl_2 gas is also effectively removed in FGD systems. Although Cl_2 is not strictly an acidic gas, it is grouped here with the "acid gas HAP" because it is controlled using the same technologies.

d. Expected Impact of Available Controls on HAP Emissions from EGUs

In 2016, EGUs are projected to account for an estimated 45 percent of anthropogenic Hg (excluding fires) in the continental U.S. Application of available Hg controls in 2016 that would be required under section 112 reduces

Hg emissions from 29 down to 6 tons, achieving a 23 tpy reduction of Hg from EGUs, which results in a 79 percent reduction in U.S. EGU emissions, and a 36 percent reduction of total anthropogenic Hg emissions nationally.

In 2016, EGUs are projected to account for 53 percent of total U.S. anthropogenic HCl. Application of available HCl controls in 2016 that would be required under section 112 achieves a 68,000 tpy reduction in HCl emissions (a 91 percent reduction in EGU emissions), resulting in a 49 percent reduction of anthropogenic emissions nationally.

Metal HAP emissions are a component of PM, and are expected to be reduced along with PM as a result of application of PM controls. In 2016, application of controls required under section 112 is expected to provide an average reduction in PM for the continental U.S. of 38 percent. Although no specific projection of metals is available for 2016, applying the 38 percent reduction in PM to the 2010 ICR emissions levels of anthropogenic metals,[129] results in reductions of approximately 430 tons of metals per year.[130]

EPA believes these projected reductions in Hg, acid gases, and metal HAP emissions demonstrate the effectiveness of available controls.

6. Consideration of the Role of U.S. EGU Hg Emissions in the Global Effort To Decrease Hg Loadings in the Environment

This would allow the U.S. to demonstrate effective technologies to reduce Hg; such leadership could provide confidence to other countries that they can succeed in meeting their commitments. Mercury pollution is a significant international environmental challenge, and it is well understood that efforts that reduce Hg emissions in other countries will reduce Hg that impacts U.S. public health and the environment. Recognizing this, EPA and others in the U.S. Government are actively involved in international efforts to reduce Hg pollution. These efforts include global negotiations aimed at concluding a legally-binding agreement to reduce Hg that were initiated in February 2009 under the UNEP.[131] Negotiation of the agreement is not expected to be completed until early 2013. Once the international process is complete, the agreement must be ratified domestically before the agreement will become binding in the U.S. The agreement is expected to cover major man-made sources of air Hg emissions, including coal-fired EGUs. Current negotiations are considering the application of best available technologies and practices to reduce air Hg emissions significantly. Regulations such as the proposed rule demonstrate the U.S. commitment to addressing the global Hg problem by decreasing the largest source of Hg emissions in the U.S. and serve to encourage other countries to address Hg emissions from their own sources.

7. It Remains Appropriate and Necessary To Regulate EGUs To Address Public Health and Environmental Hazards Associated With Emissions of Hg and Non-Hg HAP From EGUs

The extensive analyses summarized above confirm that it remains appropriate and necessary today to regulate EGUs under section 112. It is appropriate to regulate emissions from coal- and oil-fired EGUs under CAA section 112 because: (1) Hg and non-Hg HAP continue to pose a hazard to public health, and U.S. EGU emissions cause and/or contribute to this hazard; (2) Hg and some non-Hg HAP pose a hazard to the environment; (3) U.S. EGU emissions, accounting for 45 percent of U.S. Hg emissions, are still the largest domestic source of U.S. Hg emissions (by 2016, EPA projects that U.S. EGU Hg emissions will be over 6 times larger than the next largest source, which is iron and steel manufacturing), as well as the largest source of HCl and HF emissions, and a significant source of other HAP emissions; (4) Hg emissions from individual EGUs leads to hot spots of deposition in areas directly surrounding those individual EGUs, and, thus, deposition is not solely the result of regionally transported emissions, and will not be adequately addressed through reductions in regional levels of Hg emissions, requiring controls to be in place at all U.S. EGU sources that emit Hg; (5) Hg emissions from EGUs affect not only deposition, exposures, and risk today, but may contribute to future deposition, exposure and risk due to the processes of reemission of Hg that occur given the persistent nature of Hg in the environment—the delay in issuing Hg regulations under section 112 has already resulted in several hundred additional tons of Hg being emitted to the environment, and that Hg will remain part of the global burden of Hg; and (6) effective controls for Hg and non-Hg HAP are available for U.S. EGU sources.

EPA concludes that Hg emissions from U.S. EGUs are a public health hazard today due to their contribution to Hg deposition that leads to potential MeHg exposures above the RfD. EPA also concludes that U.S. EGU Hg emissions contribute to environmental concentrations of Hg that are harmful to wildlife and can affect production of important ecosystem services, including recreational hunting and fishing, and wildlife viewing. EPA further concludes that non-Hg HAP emissions from U.S. EGU are a public health hazard because they contribute to elevated cancer risks.

Finally, EPA concludes that U.S. EGU's HCl and HF emissions contribute to acidification in sensitive ecosystems and, therefore, pose a risk of adverse effects on the environment.

a. U.S. EGU Hg Emissions Continue To Pose a Hazard to Public Health and the Environment

The CAA does not define what constitutes a hazard to public health. As noted earlier, the agency must use its scientific and technical expertise to determine what constitutes a hazard to public health in the context of Utility Hg emissions. Congress did provide guidance as to what it considered an important benchmark for public health hazards, particularly in regard to Hg. In section 112(n)(1)(C), Congress required the NIEHS to determine "the threshold level of Hg exposure below which adverse human health effects are not expected to occur." This threshold level is represented by the RfD, and as such, the RfD is the benchmark for determining hazards to public health that is most consistent with Congress's interpretation of adverse health effects. As a result, our assessment of the hazard to public health posed by U.S. EGU Hg emissions is focused on comparisons to the RfD of exposures caused or contributed to by U.S. EGU Hg emissions.

As described above, almost all (98 percent) of the more than 2,400 watersheds for which we have fish tissue data exceed the RfD, above which there is the potential for an increased risk of adverse effects on human health. U.S. EGU-attributable deposition of Hg contributes to a large number of those watersheds in which total potential exposures to MeHg from all sources exceed the RfD and, thus, pose a hazard to public health. For our analysis, we focused on the watersheds to which EGUs contributed at least 5 percent of the total Hg deposition and related

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[129] It is generally assumed that the same types of controls that reduce PM will also reduce metals, because they are components of the PM.

[130] This value is 38 percent of 1,140 tons, which is the total tonnage of the metals listed in Table 5, based on the 2010 ICR emissions data.

[131] Governing Council of the United Nations Environment Programme *http://www.unep.org/hazardoussubstances/Mercury/Negotiations/Mandates/tabid/3321/language/en-US/Default.aspx.*

MeHg exposures at a watershed, or contributed enough Hg deposition resulting in potential MeHg exposures above the RfD, regardless of the additional deposition from other sources of Hg deposition. We believe this is a conservative approach because any contribution of Hg to watersheds where potential exposures to MeHg exceed the RfD poses a public health hazard. Thus, because we are finding a large percentage of watersheds with populations potentially at risk even using this conservative approach, we have confidence that emissions of Hg from U.S. EGUs are causing a hazard to public health, as we believe that there are additional watersheds that have contributions at lower percent benchmarks.

In total, 28 percent of sampled watersheds have populations that are potentially at risk from exposure to MeHg based on the contribution of U.S. EGUs, either because U.S. EGU attributable deposition is sufficient to cause potential exposures to exceed the reference dose even before considering the deposition from other U.S. and non-U.S. sources, or because the U.S. EGU attributable deposition contributes greater than 5 percent of total deposition and total exposure from all sources is greater than the reference dose. At the 99th percentile fish consumption level for subsistence fishers, 22 percent of sampled watersheds where total potential exposures to MeHg exceed the RfD have a contribution from U.S. EGUs of at least 5 percent of Hg deposition.

Although the most complete estimate of potential risk is based on total exposures to Hg, including that due to deposition from U.S. EGU sources, U.S. non-EGU sources, and global sources, the deposition resulting from U.S. EGU Hg emissions is large enough in some watersheds that persons consuming contaminated fish would have exposures that exceed the RfD even before taking into account the deposition from other sources. At the 99th percentile fish consumption level for subsistence fishers, in 12 percent of the sampled watersheds, U.S. EGUs are responsible for deposition that causes the RfD to be exceeded, even before considering the additional deposition from other sources.

In addition, we believe the estimate of where populations may be at risk from U.S. EGU-attributable Hg deposition is likely understated because the data on fish tissue MeHg concentrations is limited in some regions of the U.S., such as Pennsylvania, with very high U.S. EGU attributable Hg deposition, and it is possible that watersheds with potentially high MeHg exposures were excluded from the risk analysis.[132] In addition, due to limitations in our models and available data, we have not estimated risks in near-coastal waters, and some of these waters, including the Chesapeake Bay, have EGU-attributable Hg deposition.

Further, scientific studies have found strong evidence of adverse impacts on species of fish-eating birds with high bird-watching value, including loons, white ibis, and great snowy egrets. Studies have also shown adverse effects on insect-eating birds including many songbirds. Adverse effects in fish-eating mammals, such as mink and otter, include neurological responses (impaired escape and avoidance behavior) which can influence survival rates. Because EGUs contribute to Hg deposition in the U.S., we reasonably conclude that EGUs are contributing to the identified adverse environmental effects.

Mercury emitted into the atmosphere persists for years, and once deposited, can be reemitted into the atmosphere due to a number of processes, including forest fires and melting of snow packs. As a result, Hg emitted today can have impacts for many years. In fact, Hg emitted by U.S. EGUs in the past, including over the last decade, is still having impacts on concentrations of Hg in fish today. Failing to control Hg emissions from U.S. EGU sources will result in long term environmental loadings of Hg, above and beyond those loadings caused by immediate deposition of Hg within the U.S. Although we are not able to quantify the impact of U.S. EGU emissions on the global pool of Hg, U.S. EGUs do contribute to that global pool. Controlling Hg emissions from U.S. EGUs helps to reduce the potential for environmental hazard from Hg now and in the future. These findings independently support a determination that it is appropriate to regulate HAP emissions from EGUs.

b. U.S. EGU Non-Hg HAP Emissions Continue To Pose a Hazard to Public Health and the Environment

EPA recently conducted 16 case studies of U.S. EGUs for which we had 2007 to 2009 emissions data (based on the 2010 ICR) and that we anticipated would have relatively higher emissions of non-Hg HAP compared to other U.S. EGUs. Of the 16 facilities modeled, 4 facilities, 3 coal and 1 oil facility, have estimated risks of greater than 1 in 1 million for the most exposed individual. Although section 112(n)(1)(A) does not specify what constitutes a hazard to public health for the purposes of the appropriate and necessary finding, CAA section 112(c)(9) is instructive. As explained in section III.A above, for carcinogenic HAP, section 112(c)(9) contains a test for delisting source categories based on lifetime risk of cancer. That test reflects Congress' view as to the level of health effects associated with HAP emissions that Congress thought warranted continued regulation under section 112. Specifically, section 112(c)(9) provides that a source category can be delisted only if no source emits HAP in quantities which may cause a lifetime risk of cancer greater than 1 in 1 million to the most exposed individual. As noted above, the results of the case study risk analysis confirm that sources in the EGU source category emit HAP in quantities that cause a lifetime risk of cancer greater than 1 in 1 million. Given Congress' determination that categories of sources which emit HAP resulting in a lifetime cancer risk greater than 1 in 1 million should not be removed from the section 112(c) source category list and should continue to be regulated under 112, we believe risks above that level represent a hazard to public health such that it is appropriate to regulate EGUs under section 112.

Although our case studies did not identify significant chronic non-cancer risks from acid gas emissions from the specific EGUs assessed, the Administrator remains concerned about the potential for acid gas emissions to add to already high atmospheric levels of other chronic respiratory toxicants and to environmental loading and degradation due to acidification. EGUs emit over half of the nationwide emissions of HCl and HF, based on 2010 emissions estimates. In addition, given that many sensitive ecosystems across the country are experiencing acidification, it is appropriate to reduce emissions of this magnitude which carry the potential to aggravate acidification. The Administrator concludes that, in addition to the regulation of non-Hg HAP which cause elevated cancer risks, it is appropriate to regulate those HAP which are not known to cause cancer but are known to contribute to chronic non-cancer toxicity and environmental degradation, such as the acid gases.

These findings independently support a determination that it is appropriate to regulate HAP emissions from EGUs.

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[132] An analysis of the impact of sampling location limitations on coverage of high U.S. EGU deposition watersheds is provided in the National Scale Mercury Risk Assessment TSD.

c. Effective Controls Are Available To Reduce Hg and Non-Hg HAP Emissions

Particle-bound Hg can be effectively removed along with other flue gas PM (including non-Hg metal HAP) in primary or secondary PM control devices. Electrostatic precipitators, FF, and wet FGD scrubbers are all effective at removing Hg, with the degree of effectiveness depending on the specific characteristics of the EGU and fuel types. These devices are all effective in removing metal HAP as well. Activated carbon injection is the most successfully demonstrated Hg-specific control technology, although performance may be reduced when used with high sulfur coals. Acid gases are readily removed in typical FGD systems due to their solubility or their acidity (or both). The availability of controls for HAP emissions from EGUs supports the appropriate finding because sources will be able to reduce their emissions effectively and, thereby, reduce the hazards posed by HAP emissions from EGUs.

d. The Administrator Finds That It Remains Necessary To Regulate Coal- and Oil-Fired EGUs Under CAA Section 112

EPA determined that in 2016 the hazards posed to human health and the environment by HAP emissions from EGUs will not be addressed; therefore, it is necessary to regulate EGUs under section 112. In addition, it is necessary to regulate EGUs under section 112 because the only way to ensure permanent reductions in U.S. EGU emissions of HAP and the associated risks to public health and the environment is through standards set under section 112.

The Agency first evaluates whether it is necessary to regulate HAP emissions from EGUs "after imposition of the requirements of the CAA." As explained above, we interpret that phrase to require the Agency to consider only those requirements that Congress directly imposed on EGUs through the CAA as amended in 1990 and for which EPA could reasonably predict HAP emission reductions at the time of the Study. Nonetheless, the Agency recognizes that it has discretion to look beyond the Utility Study in determining whether it is necessary to regulate EGUs under section 112. Because several years have passed since the December 2000 Finding, we conducted an additional, updated analysis, examining a broad array of diverse requirements.

Specifically, we analyzed EGU HAP emissions remaining in 2016. Our analysis included the proposed Transport Rule; CAA section 112(g); the ARP; Federal, state, and citizen enforcement actions related to criteria pollutant emissions from EGUs; and some state rules related to criteria pollutant emissions. We included state requirements and citizen and state enforcement action settlements associated with criteria pollutants because those requirements may have a basis under the CAA. We did not, however, conduct an analysis to determine whether the requirements are, in fact, based on requirements of the CAA. As such, we believe there may be instances where we should not have considered certain state rules or state and citizen suit enforcement settlements in our analysis, because those requirements are based solely in state law and are not required by Federal law. We did not include in our analysis any state-only requirements or voluntary actions to reduce HAP emissions because we knew there was no Federal backstop for those requirements and actions.

Our analysis confirms that Hg emissions from EGUs remaining in 2016 still pose a hazard to public health and the environment and, for that reason, it remains necessary to regulate EGUs under section 112. Specifically, we estimate that U.S. EGU emissions of Hg after imposition of the requirements of the CAA will be 29 tpy in 2016, the same as the level of Hg emitted today. As we stated above, we evaluated the hazards to public health and the environment from Hg based on the estimated Hg emissions in 2016 and found that a hazard exists. Because a hazard remains after imposition of the requirements of the CAA, it is necessary to regulate EGUs.

It is necessary to regulate HAP emissions from EGUs, even though the hazards from Hg will not be resolved through regulation under section 112. EPA finds that incremental reductions in Hg are important because as exposure above the RfD increases the likelihood and severity of adverse effects increases.

EGUs are the largest source of Hg in the U.S. and, thus, contribute to the risk associated with exposure to MeHg. By reducing Hg emissions from U.S. EGUs, this proposed rule will help to reduce the risk to public health and the environment from Hg exposure.

We also find that it is necessary to regulate EGUs under section 112 based on non-Hg HAP emissions because we cannot be certain that the identified cancer risks attributable to EGUs will be addressed through imposition of the requirements of the CAA. In addition, the environmental hazards posed by acidification will not be fully addressed through imposition of the CAA.

We also find it necessary to regulate EGUs because regulation under section 112 is the only way to ensure that HAP emissions reductions that have been achieved since 2005 remain permanent.

The difference between the 53 ton 2005 estimate and the 2010 ICR-based estimate of total EGU emissions may be overstated. While EPA has estimated 2010 total EGU Hg emissions of 29 tons based on data from the 2010 ICR database, this may underestimate total 2010 EGU Hg emissions due to the fact that emission factors used to develop the estimates may not accurately account for larger emissions from units with more poorly performing emission controls. The 2010 ICR by which the data used to develop the factors was collected was designed to provide the agency the data to determine the appropriate MACT levels and was not designed to collect data to fully characterize all units' Hg emissions, particularly those that might have poorly performing controls. EPA tested only 50 randomly selected units that were not selected for testing as best performing units (the bottom 85 percent of units), and we used that small sample to attempt to characterize the lower performing units. Because the 50 units were randomly selected, we do not believe we have sufficiently characterized the units that have poorly performing controls. In addition, the methodology for estimating the 2005 and 2010 emission estimates are not the same. The 2005 estimate is based on control configurations as of 2002, therefore, it does not reflect reductions due to control installations that took place between 2002 and 2005. As a result, the apparent difference between 2005 and 2010 is overstated. There are real factors that explain why Hg reductions would have occurred between 2005 and 2010. The actual reductions between 2005 and 2010 are attributable to state Hg regulations and to CAIR and Federal enforcement actions that achieve Hg reductions as a co-benefit of controls for PM, NO_X, and SO_2 emissions. However, there are no national, Federally binding regulations for Hg. State Hg regulations can potentially change or be revoked without EPA approval, and reductions that occur as a co-benefit of criteria pollutant regulations can also change. Furthermore, companies can change their criteria pollutant compliance strategies and use methodologies that do not achieve the same level of Hg or other HAP co-benefit (*e.g.,* purchasing allowances in a trading program instead of using add-on controls).

As with Hg, the most recent data on U.S. EGU HCl and HF emissions show a significant reduction between 2005 and 2010. These reductions in HCl and HF are the co-benefit of controls installed to meet other CAA requirements, including enforcement actions, and to a lesser extent, state regulations. There is no guarantee other than regulation under section 112 that these significant decreases in HCl and HF emissions will be permanent. Although we do not have estimates for the remaining HAP emitted from EGUs, we believe it is likely that such emissions have also decreased between 2005 and 2010. Thus, the Administrator finds it necessary to regulate HAP emissions from EGUs to ensure that HAP emissions reductions are permanent.

Finally, direct control of Hg emissions affecting U.S. deposition is only possible through regulation of U.S. emissions; we are unable to control global emissions directly. Although the U.S. is actively involved in international efforts to reduce Hg pollution, the ability of the U.S. to argue effectively in these negotiations for strong international policies to reduce Hg air emissions depends in large part on our domestic policies, programs and regulations to control Hg.

All of these findings independently support a finding that it is necessary to regulate EGUs under section 112.

Therefore, given the Agency's finding that it remains appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112, EPA is confirming its inclusion of coal- and oil-fired EGUs on the list of source categories regulated under CAA section 112(c).

8. Implications of Hazards to Public Health for Children and Environmental Justice Communities

Children are at greatest risk of adverse health effects from exposures to Hg, and this risk is amplified for children in minority and low income communities who subsist on locally-caught fish. Today's proposed rule is therefore an important step in addressing disparate impacts on children and environmental justice (EJ) communities.

Children are more vulnerable than adults to many HAP, because of differences in physiology, higher per body weight breathing rates and consumption, rapid development of the brain and bodily systems, and behaviors that increase chances for exposure. Even before birth, the developing fetus may be exposed to HAP through the mother that affect development and permanently harm the individual. Infants and children breathe at much higher rates per body weight than adults, with infants under one year of age having a breathing rate up to five times that of adults.[133] In addition, children breathe through their mouths more than adults and their nasal passages are less effective at removing pollutants, which leads to a higher deposition fraction in their lungs.[134] Crawling and frequent hand-to-mouth activity lead to infants' higher levels of ingestion of contaminants deposited onto soil or in dust. Infants' consumption of breast milk can pass along high levels of accumulated persistent bioaccumulative pollutants from their mothers. Children's dietary intake also exceeds that of adults, per body weight, posing a potential added risk from persistent HAP that accumulate in food. In addition to the greater exposure, the less-well developed detoxification pathways and rapidly developing systems and organs put children at potentially greater risk.

Mercury is the HAP from EGUs of most concern to early life stages. The adverse affects of Hg on developing neuropsychological systems is well-established and permanent. The prenatal period of development has been established to be the most sensitive lifestage to the neurodevelopmental effects of MeHg.[135] Children who are exposed to low concentrations of MeHg prenatally are at increased risk of poor performance on neurobehavioral tests, such as those measuring attention, fine motor function, language skills, visual-spatial abilities, and verbal memory.[136] [137] Impaired cognitive development from exposures to MeHg prenatally and in early childhood affect the individual into adulthood, by affecting learning and potential future earnings, and contributing to behavioral problems.

Other HAP related to EGU emissions present greater risks to children as well. For example, mutagenic carcinogens such as Cr^{+6} have a larger impact during young lifestages, given the rapid development of the corporal systems.[138] Exposure at a young age to these carcinogens could lead to a higher risk of developing cancer later in life.

The adverse effects of individual non-Hg HAP may be more severe for children, particularly the youngest age groups, than adults. A number of epidemiologic studies suggest that children are more vulnerable than adults to lower respiratory symptoms associated with PM.[139] [140] Non-Hg metal HAP may behave similarly to particulate matter, at least in terms of the deposition fraction that reaches children's lungs. As with Hg, Pb and Cd are known to affect children's neurologic development. A meta-analysis of seven studies has shown an association between exposure to formaldehyde, another HAP of concern, and development of asthma in children.[141]

Within communities overburdened with environmental exposures, the youngest lifestages are likely the most vulnerable. Looking at the health effects for children in those communities can be an important part of appropriately assessing community risks.

EPA has also considered the effects of this rule on EJ communities. The nature of exposures to Hg is such that populations with high levels of self-caught fish consumption are likely to be disproportionately affected. EPA's risk analysis identified many EJ communities, including Laotian, Vietnamese, Hispanic, African-American, tribal, and low income communities, as having higher levels of subsistence fishing activities. Consequently, individuals in these

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[133] U.S. Environmental Protection Agency. 2006. *Revision of the metabolically-derived ventilation rates within the Exposure Factors* Handbook. (External review draft) Washington, DC: Office of Research and Development. EPA/600/R–06/129A. *http://oaspub.epa.gov/eims/eimscomm.getfile?p_download_id=460261.*

[134] Foos, B., M. Marty, J. Schwartz, W. Bennett, J. Moya, A. M. Jarabek, and A. G. Salmon. 2008. Focusing on children's Inhalation Dosimetry and Health Effects for Risk Assessment: An Introduction. *J Toxicol Environ Health* 71A: 149–165.

[135] National Academy of Sciences. 2000. *Toxicological Effects of Methylmercury.* Washington, DC: National Academy Press. *http://books.nap.edu/catalog/9899.html?onpi_newsdoc071100.*

[136] P. Grandjean, P. Weihe, R.F. White, F. Debes, S. Araki, K. Yokoyama, K. Murata, N. Sorensen, R. Dahl and P.J. Jorgensen. 1997. Cognitive deficit in 7-year-old children with prenatal exposure to methylmercury. *Neurotoxicology and Teratology* 19 (6):417–28.

[137] T. Kjellstrom, P. Kennedy, S. Wallis and C. Mantell. 1986. *Physical and mental development of children with prenatal exposure to mercury from fish. Stage 1: Preliminary tests at age 4.* Sweden: Swedish National Environmental Protection Board.

[138] U.S. Environmental Protection Agency. 2005. *Supplemental Guidance for Assessing Susceptibility from Early-Life Exposure to Carcinogens.* Washington, DC: Risk Assessment Forum. EPA/630/R-03/003F *http://www.epa.gov/raf/publications/pdfs/childrens_supplement_final.pdf*

[139] Pope, C.A. and D.W. Dockery. 1992. Acute health effects of PM10 pollution on symptomatic and asymptomatic children. *Am Rev Respir Dis* 145: 1123–1128.

[140] Gauderman, W.J., R. McConnell, F. Gilliland, S. London, et al. 2000. Association between air pollution and lung function growth in Southern California children. *Am J Respir Crit Care Med* 162: 1283–1390.

[141] McGwinn, G. Jr., J. Lienert, and J.I. Kennedy Jr. 2010. Formaldehyde Exposure and Asthma in Children: A Systematic Review. *Environ Health Perspect* 118: 313–317.

communities are potentially exposed to levels of MeHg in fish that may result in these individuals' exposure exceeding the RfD. These EJ populations are thus at higher risk for the health effects associated with exposures to MeHg, which include impacts on neurological functions that can cause children to struggle in school. In EJ populations which often face numerous other stressors that can result in lower educational performance, the additional burdens imposed by exposure to Hg may cause significant and long-lasting impacts on children that continue into adulthood, affecting learning potential and measures of IQ, including future earnings and indicators of quality of life.

9. The Analysis Supporting the 2005 Action Was Subject to Technical Limitations and These Flaws Undermine the Basis for the 2005 Action

In 2005, EPA conducted a set of technical analyses to support a revision to the 2000 appropriate and necessary finding.[142] In those analyses, EPA made several assumptions that were not justified based on scientific or technical grounds, and which we have corrected in our technical analysis supporting our current confirmatory finding that it is appropriate and necessary to regulate coal- and oil-fired EGUs under section 112.

a. Interpretation of the MeHg Reference Dose and Incremental U.S. EGU-Attributable Exposures

In the 2005 analysis, EPA made the following statement:

> The RfD provides a useful reference point for comparisons with measured or modeled exposure. The Agency defines the RfD as an exposure level below which the Agency believes exposures are likely to be without an appreciable risk over a lifetime of exposure. For the purposes of assessing population exposure due to EGUs, we create an index of daily intake (IDI). The IDI is defined as the ratio of exposure due solely to EGUs to an exposure of 0.1 µg/kg bw/day. The IDI is defined so that an IDI of 1 is equal to an incremental exposure equal to the RfD level, recognizing that the RfD is an absolute level, while the IDI is based on incremental exposure without regard to absolute levels. Note that an IDI value of 1 would represent an absolute exposure greater than the RfD when background exposures are considered.[143]

Upon further consideration, EPA concludes that it did not have a scientific or technical justification for creating a metric other than the HQ[144] to compare U.S. EGU-attributable exposures to the RfD. As EPA recognized in 2005, the RfD is an absolute level above which the potential risks of exposures increase, based on total exposures to MeHg. The concept of the IDI was created by EPA in 2005 solely to support its interpretation that it must assess hazards to public health solely based on U.S. EGU emissions with no consideration of exposures to MeHg arising from other sources of Hg deposition. As noted above, nothing in section 112(n)(1)(A) prohibits consideration of HAP emissions from U.S. EGUs in conjunction with HAP emissions from other sources of HAP, including sources outside the U.S. Indeed, such an approach would ignore the manner in which the public is actually exposed to HAP emission. By focusing on whether incremental exposures attributable to U.S. EGU Hg emissions exceeded the RfD without consideration of other exposures, EPA implied that U.S. EGU Hg emissions were not causing a hazard to public health even though such emissions were increasing risks in locations where the RfD was already exceeded due to total exposures from all Hg sources, including U.S. EGU emissions. This is a serious flaw in EPA's 2005 assessment, due to reasons we discuss below.

Ninety-eight percent of watersheds with fish tissue MeHg samples have Hg deposition levels such that total potential exposure to MeHg exceeds the RfD, and many have exposures that are many times the RfD.[145] As a result, in almost all watersheds with fish tissue MeHg samples, *any* additional Hg will increase potential risk. Thus, U.S. EGU-attributable Hg deposition is contributing to increased potential risk. The Agency believes the assessment of potential risk due to Hg emissions from U.S. EGUs must consider both the extent to which U.S. EGUs contribute to such risk along with other sources, and the extent to which U.S. EGU-attributable deposition leads to exposures that exceed the RfD even before considering the contributions of other sources of Hg. The Agency has conducted such an evaluation in the national-scale MeHg risk analysis presented above. In 2005, as a result of relying on a flawed, non-scientific approach for comparing MeHg exposures to the RfD, and a failure to consider cumulative risk characterization metrics, EPA incorrectly determined that U.S. EGU emissions of Hg did not constitute a hazard to public health. As discussed above, EPA has revised this determination and concluded that U.S. EGU Hg emissions are a hazard to public health because they cause exposures to exceed the RfD or contribute to exposures in watersheds where total exposures to MeHg exceed the RfD.

b. Interpretation of Populations Likely To Be at Risk and Conclusions Regarding Acceptable Risk

In addition to developing a flawed exposure indicator based on only U.S. EGU attributable exposure (the IDI), EPA also erred in finding that exposures above the RfD (an IDI greater than 1) did not pose an "unacceptable risk" (*e.g.,* did not pose a hazard to public health). EPA cited three reasons for the finding in 2005: (1) Lack of confidence in the risk estimates; (2) lack of seriousness of the health effects of MeHg; and (3) small size of the population at risk and low probability of risks in that population. EPA was not justified in making its determination based on these three factors.

In the 2005 Action, EPA cited the underpinnings of the RfD as introducing a degree of conservatism. In fact, however, as discussed above, EPA has stated consistently, including in the RfD issued in 2001, that the RfD for Hg is a level above which there is the potential for increased risk. Only at levels at or below the RfD does the Agency maintain that exposures are without *significant* risk. EPA's interpretation in 2005 was a departure from prior EPA policy as it concerns exposures to Hg and was in error.

In the 2005 Action, EPA identified 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 as the primary health effects of MeHg exposures. Although not stated explicitly, it is implicit in the 2005 Action that EPA did not consider these health effects to be serious. The Agency did not, and could not have, provided any scientific or policy rationale for dismissing these serious public health effects. For example, as mentioned

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[142] U.S. EPA. 2005. Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls.

[143] U.S. EPA. 2005. Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls.

[144] The HQ is the ratio of observed or modeled exposures to the RfD.

[145] *See* the National Scale Mercury Risk Assessment Technical Support Document.

above, there are potentially serious implications of the identified effects on learning potential and measures of IQ, including future earnings and indicators of quality of life. EPA was not justified in dismissing these health effects as not serious without providing evidence or justification, which it could not do based on the information available at the time or today.

In the 2005 Action, EPA made several statements in the technical analysis suggesting that the probability that an IDI of 1 would be exceeded (*e.g.,* that U.S. EGU attributable exposures would be greater than the RfD) was low due to the rare occurrence of high consumption rate populations in high deposition watersheds. The 2005 analysis showed that 15 percent of watersheds would have U.S. EGU-attributable potential exposures that were twice the RfD for the highest fish consumption rates. EPA dismissed this high percent of watersheds by stating that those high fish consumption rates would only occur in Native American populations, and that those populations lived in locations that were not heavily impacted by U.S. EGU Hg deposition.

Information was available at the time of the 2005 analysis indicating that other populations besides Native Americans engaged in subsistence fishing activities that would result in consumption rates similar to Native Americans. EPA chose to selectively use information only on Native American consumption rates and erroneously concluded that subsistence fishing activities would not occur in a wider set of locations. This choice was in error, as EPA should have investigated whether other subsistence populations could fish in locations heavily impacted by U.S. EGU emissions (*e.g.,* watersheds with the top 15 percent of U.S. EGU-attributable fish tissue MeHg levels). A search of the literature available in 2005 reveals several studies that identified additional fishing populations with subsistence or near subsistence consumption rates, including urban fishing populations (including low-income populations),[146] [147] [148] Laotian communities,[149] and Hispanics. In fact, EPA participated in 1999 in a project investigating exposures of poor, minority communities in New York City to a number of contaminants including Hg, and should thus have been aware that these populations can have very high consumption rates.[150] If EPA had conducted a thorough investigation in 2005, it should have concluded that populations with the potential for subsistence-level fish consumption rates occur in many watersheds, and, thus, could not have concluded that exposures above the RfD (IDI greater than 1) were not likely.

Thus, based on the errors EPA made in the 2005 Action related to evaluating the risks from MeHg exposures attributable to U.S. EGUs, EPA's technical determination in 2005 that risks were acceptable based on that analysis was not justified. As a result the technical determination in 2005 which supported the finding of no public health hazard, and the determination that it was not appropriate or necessary to regulate HAP from U.S. EGUs was in error.

IV. Summary of This Proposed NESHAP

This section summarizes the requirements proposed in this proposed rule. Our rationale for the proposed requirements is provided in Section V of this preamble.

A. What source categories are affected by this proposed rule?

This proposed rule affects coal- and oil-fired EGUs.

B. What is the affected source?

An existing affected source for this proposed rule is the collection of coal- and oil-fired EGUs within a single contiguous area and under common control. A new affected source is a coal- or oil-fired EGU for which construction or reconstruction began after May 3, 2011.

CAA section 112(a)(8) defines an EGU 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 an EGU burns coal (either as a primary fuel or as a supplementary fuel), or any combination of coal with another fuel (except as noted below), the unit is considered to be coal fired under this proposed rule. If a unit is not a coal-fired unit and burns only oil, or oil in combination with another fuel other than coal (except as noted below), the unit is considered to be oil fired under this proposed rule. As noted below, EPA is proposing a definition to determine whether the combustion unit is "fossil fuel fired" such that it is an EGU for purposes of this proposed rule. The unit must be capable of combusting more than 73 megawatt-electric (MWe) (250 million British thermal units per hour, MMBtu/hr) heat input (equivalent to 25 MWe electrical output) of coal or oil. In addition, using the construct of the definition of "oil-fired" from the ARP, we are proposing that the unit must have fired coal or oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years to be considered a "fossil fuel fired" EGU subject to this proposed rule. If a new or existing EGU is not coal- or oil-fired, and the unit burns natural gas exclusively or natural gas in combination with another fuel where the natural gas constitutes 90 percent or more of the average annual heat input during the previous 3 calendar years or 85 percent or more of the annual heat input during any 1 of those calendar years, the unit is considered to be natural gas-fired and would not be subject to this proposed rule. As discussed later, we believe that this definition will address those situations where either an EGU fires coal or oil on only a limited basis or co-fires limited amounts of coal or oil with other non-fossil fuels (*e.g.,* biomass).

To the extent a unit combusts solid waste, that unit is not an EGU under section 112, but rather would be subject to CAA section 129.

The Small Entity Representatives (SERs) serving on the Small Business Advocacy Review Panel (SBAR) established under the Small Business Regulatory Enforcement Fairness Act (SBREFA) suggested that EPA consider developing an area-source (*i.e.,* those EGUs emitting less than 10 tpy of any one HAP or less than 25 tpy of any combination of HAP) vs. major-source (*i.e.,* those EGUs emitting 10 tpy or more of any one HAP or 25 tpy of more of any

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[146] Burger, J., K. Pflugh, L. Lurig, L. Von Hagen, and S. Von Hagen. 1999. Fishing in Urban New Jersey: Ethnicity Affects Information Sources, Perception, and Compliance. Risk Analysis 19(2): 217–229.

[147] Burger, J., Stephens, W., Boring, C., Kuklinski, M., Gibbons, W.J., & Gochfield, M. (1999). Factors in exposure assessment: Ethnic and socioeconomic differences in fishing and consumption of fish caught along the Savannah River. Risk Analysis, 19(3).

[148] Chemicals in Fish Report No. 1: Consumption of Fish and Shellfish in California and the United States Final Draft Report. Pesticide and Environmental Toxicology Section, Office of Environmental Health Hazard Assessment, California Environmental Protection Agency, July 1997.

[149] Tai, S. 1999. "Environmental Hazards and the Richmond Laotian American Community: A Case Study in Environmental Justice." Asian Law Journal 6: 189.

[150] Corburn, J. (2002). Combining community-based research and local knowledge to confront asthma and subsistence-fishing hazards in Greenpoint/Williamsburg, Brooklyn, New York. Environmental Health Perspectives, 110(2).

combination of HAP) distinction for this source category. The proposed rule treats all EGUs the same and proposes MACT standards for all units.

Nothing in the CAA requires that we issue GACT standards for area sources. Indeed, here, the data show that similar HAP emissions and control technologies are found on both major and area sources greater than 25 MWe. In fact, because of the significant number of well-controlled EGUs of all sizes, we believe it would be difficult to make a distinction between MACT and GACT. Moreover, EPA believes the standards for area source EGUs should reflect MACT, rather than GACT, because there is no essential difference between area source and major source EGUs with respect to emissions of HAP. There are EGUs that are physically quite large that are area sources, and EGUs that are small that are major sources. Both large and small EGUs are represented in the MACT floor pools for acid gas, Hg, and non-Hg metal HAP. Finally, given that EPA is regulating both major and area source EGUs at the same time in this rulemaking, a common control strategy consequently appears warranted for these emissions.

If area sources tend to be very different from major sources and the capacity to control those sources is different, we could exercise our discretion under section 112(d)(5) to set GACT standards for area sources. But, as explained above, that is not the case here. Accordingly, we believe it is appropriate to set MACT standards for both major and area source EGUs. EPA solicits comment on its proposed approach. Specifically, we solicit comments on whether there would be a basis for considering area sources to be significantly different from major sources with respect to issues relevant to standard setting. Commenters should also explain the basis of their suggested approach and how that approach would lead to similar health and environmental benefits, including data that would underpin a GACT analysis.[151]

C. Does this proposed rule apply to me?

This proposed rule applies to you if you own or operate a coal- or oil-fired EGU as defined in this proposed rule.

D. Summary of Other Related DC Circuit Court Decisions

In March 2007, the DC Circuit Court issued an opinion (*Sierra Club* v. *EPA,* 479 F.3d 875 (DC Cir. 2007)) (Brick MACT) vacating and remanding CAA section 112(d) NESHAP for the Brick and Structural Clay Ceramics source categories. Some key holdings in that case were:

- Floors for existing sources must reflect the average emission limitation achieved by the best-performing 12 percent of existing sources, not levels EPA considers to be achievable by all sources (479 F.3d at 880–81);
- EPA cannot set floors of "no control." The DC Circuit Court reiterated its prior holdings, including *National Lime Ass'n.* v. *EPA* (233 F.3d625 (DC Cir. 2000)) (*National Lime II*), confirming that EPA must set floor standards for all HAP emitted by the source, including those HAP that are not controlled by at-the-stack control devices (479 F.3d at 883);
- EPA cannot ignore non-technology factors that reduce HAP emissions. Specifically, the DC Circuit Court held that "EPA's decision to base floors exclusively on technology even though non-technology factors affect emissions violates the Act." (479 F.3d at 883.) The DC Circuit Court also reiterated its position stated in *Cement Kiln Recycling Coalition* v. *EPA,* 255 F.3d 855 (DC Cir. 2001) that CAA section 112(d)(3) "requires floors based on the emission level actually achieved by the best performers (those with the lowest emission levels)."

Based on the *Brick MACT* decision, we believe a source's performance resulting from the presence or absence of HAP in fuel materials must be accounted for in establishing floors (*i.e.,* a low emitter due to low HAP fuel materials can still be a best performer). In addition, the fact that a specific level of performance is unintended is not a legal basis for excluding the source's performance from consideration. *National Lime II;* 233 F.3d at 640.

The *Brick MACT* decision also stated that EPA may account for variability in setting floors. The DC Circuit Court found that "EPA may not use emission levels of the worst performers to estimate variability of the best performers without a demonstrated relationship between the two." 479 F.3d at 882.

A second DC Circuit Court opinion is also relevant to this proposal. In *Sierra Club* v. *EPA,* 551 F.3d 1019 (DC Cir. 2008), the DC Circuit Court vacated the portion of the regulations contained in the General Provisions which exempt major sources from NESHAP during periods of startup, shutdown and malfunction (SSM). The regulations (in 40 CFR 63.6(f)(1) and 63.6(h)(1)) provided that sources need not comply with the relevant CAA section 112(d) standard during SSM events and instead must "minimize emissions * * * to the greatest extent which is consistent with safety and good air pollution control practices." As a result of the DC Circuit Court decision, sources must comply with the emission standards at all times and we are addressing SSM in this proposed rulemaking. Discussion of this issue may be found later in this preamble.

A third relevant DC Circuit Court opinion is *National Lime II* (233 F.3d 625), where, in considering whether EPA may use PM, a criteria pollutant, as a surrogate for metal HAP, the DC Circuit Court stated that EPA "may use a surrogate to regulate hazardous pollutants if it is 'reasonable' to do so" and laid out criteria establishing a three-part analysis for determining whether the use of PM as a surrogate for non-Hg metal HAP was reasonable. The DC Circuit Court found that PM is a reasonable surrogate for HAP if: (1) "HAP metals are invariably present in * * * PM;" (2) "PM control technology indiscriminately captures HAP metals along with other particulates;" and (3) "PM control is the only means by which facilities 'achieve' reductions in HAP metal emissions." 233 F.3d at 639. If these criteria are satisfied and the PM emission standards reflect what the best sources achieve—complying with CAA section 7412(d)(3)—"EPA is under no obligation to achieve a particular numerical reduction in HAP metal emissions." We have considered this case in evaluating whether the surrogate standards we propose to establish in this proposed rule are reasonable.

E. EPA's Response to the Vacatur of the 2005 Action

After the vacatur of the Revision Rule, EPA evaluated the HAP and other emissions data available to establish CAA section 112(d) standards for coal- and oil-fired EGUs and determined that additional HAP emission data were required. EPA initiated an information collection effort entitled "Electric Utility Steam Generating Unit Hazardous Air Pollutant Emissions Information

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[151] As we have explained in other rules, determining what constitutes GACT involves considering the control technologies and management practices that are generally available to the area sources in the source category. We also consider the standards applicable to major sources in the same industrial sector to determine if the control technologies and management practices are transferable and generally available to area sources. In appropriate circumstances, we may also consider technologies and practices at area and major sources in similar categories to determine whether such technologies and practices could be considered generally available for the area source category at issue. Finally, in determining GACT for a particular area source category, we consider the costs and economic impacts of available control technologies and management practices on that category.

Collection Effort" (OMB Control Number 2060–0631). This information collection (2010 ICR) was conducted by EPA's Office of Air and Radiation (OAR) pursuant to CAA section 114 to assist the Administrator in developing emissions standards for coal- and oil-fired EGUs pursuant to CAA section 112(d). CAA section 114(a) states, in pertinent part:

> For the purpose of * * * (iii) carrying out any provision of this Chapter * * * (1) the Administrator may require any person who owns or operates any emission source * * * to * * * (D) sample such emissions (in accordance with such procedures or methods, at such locations, at such intervals, during such periods and in such manner as the Administrator shall prescribe); (E) keep records on control equipment parameters, production variables or other indirect data when direct monitoring of emissions is impractical * * *; (G) provide such other information as the Administrator may reasonably require * * *

Prior to issuance of the information collection effort, information necessary to identify all coal- and oil-fired EGUs as defined in CAA section 112(a)(8) was publicly available for EGUs owned and operated by publicly-owned utility companies, Federal power agencies, rural electric cooperatives, investor-owned utility generating companies, and nonutility generators (such units include, but may not be limited to, independent power producers (IPPs), qualifying facilities, and combined heat and power (CHP) units). The most recent information available was for 2005, and the available information generally did not include any information on permitted HAP emission limits; or monitoring, recordkeeping, and reporting requirements for HAP emissions; and we did not have complete HAP emissions data for any EGU. Additionally, we had little current information on the fuel amounts received, fuel sources, fuel shipment methods, or results of previously conducted fuel analyses for coal- and oil-fired EGUs, or for results from tests conducted since January 1, 2005. We did not have emissions test results that would provide data for emissions of a variety of pollutants, including: PM, PM with an aerodynamic diameter equal to or less than 2.5 micrometers ($PM_{2.5}$); SO_2; HCl/HF/HCN; metal HAP (including compounds of Sb, As, Be, Cd, Cr, Co, Pb, Mn, Ni, and Se); Hg; total organic hydrocarbons (THC); volatile organic compounds (VOC); and carbon monoxide (CO).

To obtain the information necessary to evaluate coal- and oil-fired EGUs, EPA developed a two-phase ICR and published the first notice in the **Federal Register** for comment consistent with the requirements of the PRA. 74 FR 31725 (July 2, 2009). We received comments from industry and other interested parties. We also met with industry and other interested parties, and published a revised ICR in the **Federal Register** for another round of comments consistent with the PRA. 74 FR 58012 (November 10, 2009). OMB approved the ICR on December 24, 2009, and we sent the ICR to owners and operators of EGUs on December 31, 2010.

As stated above, the ICR contained two phases or components. The first component solicited information from all potentially affected units. EPA provided the survey in electronic format; however, written responses were also accepted. The survey was submitted to all coal- and oil-fired EGUs listed in the 2007 version of the DOE's Energy Information Administration's (EIA) Forms 860 and 923, "Annual Electric Generator Report," and "Power Plant Operations Report," respectively.

The second component required the owners/operators of a limited number of coal-and oil-fired EGUs to conduct stack testing in accordance with an EPA-approved protocol. Some coal-fired units were selected to be tested because we determined based on the information available that the units were among the top performing 15 percent of sources in the coal subcategory for certain types of HAP. Best-performing coal-fired units to be tested were selected to cover three groups of HAP that may be regulated through the use of surrogate standards: (1) Non-Hg metallic HAP (*e.g.,* As, Pb, Se); (2) acid gas HAP (*e.g.,* HCl, HF, HCN); (3) and non-dioxin/furan organic HAP. We also required the non-Hg metallic HAP sources to test for Hg even though Hg is to be regulated separately and not covered by any non-Hg metallic HAP surrogacy. Fifty coal-fired units were also selected at random from the entire population of coal-fired EGUs to test for dioxin/furan organic HAP. An additional 50 coal-fired units were selected at random from among those units not selected as being "top performing" units to represent those coal-fired units not comprising the top-performing units in the three HAP surrogate groups; these 50 randomly selected units were required to test for all HAP except dioxin/furan organic HAP. Data from this last grouping was collected so we could estimate the HAP emission reductions associated with the proposed standards. Oil-fired units to be tested were also selected at random to test for HAP in all three groups of HAP noted above, in addition to testing for Hg and dioxin/furan.

The testing consisted of three runs at the sampling location and was in accordance with a specified emission test method. The owner/operator of each selected EGU was also required to collect and analyze, in accordance with an acceptable procedure, three fuel samples from the fuel fed to the EGU during each stack test. Additional details of the required sampling may be found in Docket entry EPA–HQ–OAR–2009–0234–0062.

In phase one, all coal- and oil-fired EGUs identified by EPA as being potentially subject sources under the definition in CAA section 112(a)(8), including all integrated gasification combined cycle (IGCC) EGUs and all EGUs fired by petroleum coke, were required to submit information to EPA. The sources were required to provide information on the current operational status of the unit, including applicable controls installed, along with emissions information from the preceding 5 years. This information was necessary for EPA to fully characterize the category and update our database of coal- and oil-fired EGUs.

Phase two was the testing phase. As stated above, coal-fired units to be tested were selected to cover five HAP or groups of HAP, three of which may be regulated through the use of surrogate pollutant standards and were chosen because EPA determined the units were best performing units for one or more of the three HAP surrogate groups. In the stack testing, each facility was required to test after the last control device or at the stack if the stack is not shared with other units using different controls. In this way, the facility would test before any "dilution" by gases from a separately-controlled unit. Under certain circumstances, however, testing after a common control device or at the common stack was allowed.

EPA selected for testing the sources that the Agency believed, based on a variety of factors and information available to the Agency at the time, were the best performing sources for the three HAP surrogate groups for which they were required to test. In targeting the best performing sources, EPA required testing for approximately 15 percent of all coal-fired EGUs for the 3 HAP surrogate groups—non-Hg metal HAP and PM; non-dioxin/furan organic HAP, total hydrocarbon, CO, and VOC; and acid gas HAP and SO_2. As we stated in response to comments on the proposed 2010 ICR, we targeted the best performing coal-fired sources for certain HAP groups because the statute requires the Agency to set the MACT floor at the "average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has information)" in the category. By targeting the best performing 15 percent of coal-fired EGUs for testing in the 3 HAP groups, we concluded that we would have emissions data on the best performing 12 percent of all existing coal-fired EGUs. In this proposed rule, we used data from sources representing the best performing 12 percent of all sources in any category or subcategory to establish the CAA section 112(d) standards for the 3 HAP groups because we believe we have identified the best performing 12 percent of sources for those subcategories with 30 or more sources. For Hg from coal-fired units, we used the top 12 percent of the data obtained because, even though we required Hg testing for the units testing for the non-Hg metallic HAP, we did not believe those units represented the top performing 12 percent of sources for Hg in the category at the time we issued the ICR and we made no assertions to that effect. For oil-fired units, we also used the top 12 percent of the data obtained because we were unable, based on the information available, to determine the best performing oil-fired units. The primary reason for our inability to identify best performing oil-fired units is that such units are generally uncontrolled or controlled only with an ESP. The approach for both coal- and oil-fired EGUs was discussed with, and agreed upon by, several industry and environmental organization stakeholders prior to finalizing the ICR.

The acid-gas HAP, HCl and HF, are water-soluble compounds and are more soluble in water than is SO_2. (Cyanide, representing the "cyanide compounds," and Cl_2 gas are also water-soluble and are considered "acid-gas HAP" in this proposal.) Hydrogen chloride also has a large acid dissociation constant (*i.e.,* HCl is a strong acid) and it, thus, will react easily in an acid-base reaction with caustic sorbents (*e.g.,* lime, limestone). The same is true for HF. This indicates that both HCl and HF will be more rapidly and readily removed from a flue gas stream than will SO_2, even when only plain water is used. In FBC systems, the acid gases and SO_2 are adsorbed by the sorbent (usually limestone) that is added to the coal and an inert material (*e.g.,* sand, silica, alumina, or ash) as part of the FBC process.

Hydrogen chloride and HF have also been shown to be effectively removed using DSI where a dry, alkaline sorbent (*e.g.,* hydrated lime, trona, sodium carbonate) is injected upstream of a PM control device.

Chlorine in the fuel coal may also partition in small amounts to Cl_2. This is normally a very small fraction relative to the formation of HCl. Limited testing has shown that Cl_2 gas is also effectively removed in FGD systems. Although Cl_2 is not strictly an acidic gas, it is grouped here with the "acid gas HAP" because it is controlled using the same technologies.

Because the technologies for removal of the acid gases are primarily those that are also used for FGD, we consider emissions of SO_2, a commonly measured pollutant, as a potential surrogate for emissions of the acid-gas HAP HCl, HF, HCN, and Cl_2. Although use of SO_2 as a surrogate for acid gas HAP has not been used in any CAA section 112 rules by EPA, it has been used in a number of state permitting actions (*see* Docket entry EPA–HQ–OAR–2009–0234–0062). Hydrogen chloride has been used as a surrogate for the acid gas HAP in other Agency actions (*e.g.,* Portland Cement NESHAP, 75 FR 54970, September 9, 2010 (final rule); major and area source Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (collectively, Boiler NESHAP), 75 FR 32005, June 4, 2010; 75 FR 31895, June 4, 2010 (proposed rules; the final rules were signed on February 21, 2011)), and we propose to use HCl as a surrogate for all the acid gas HAP, with an alternative equivalent standard using SO_2 as a surrogate. In addition, we gathered sufficient data on HCl, HF, and HCN [152] to establish individual emission limitations if warranted.

EPA identified the units with the newest FGD controls installed for testing of acid gas HAP based on our analysis that FGD controls are the best at reducing acid gas HAP emissions. EPA also believes that the units with the newest FGD systems represent those units having to comply with the most recent, and, therefore, likely most stringent, emission limits for SO_2. We determined that efforts by units to comply with stringent SO_2 limits would also likely represent the top performers with regard to acid gas HAP emissions. Specifics of the required testing may be found in Docket entry EPA–HQ–OAR–2009–0234–0062.

Dioxin/furan emissions data were obtained in support of the 1998 Utility Report to Congress. However, approximately one-half of those data were listed as being below the minimum detection level (MDL) for the given test. Dioxin/furan emissions from coal-fired EGUs are generally considered to be low, presumably because of the insufficient amounts of available chlorine. As a result of previous work conducted on municipal waste combustors (MWC), it has also been proposed that the formation of dioxins and furans in exhaust gases is inhibited by the presence of sulfur.[153] Further, it has been suggested that if the sulfur-to-chlorine ratio (S:Cl) in the flue gas is greater than 1.0, then formation of dioxins/furans is inhibited.[154] [155] The vast majority of the coal analyses provided through the 1999 ICR effort indicated S:Cl values greater than 1.0. As a result, EPA expected that additional data gathering efforts would continue the trend of data being at or below the MDL. Even so, EPA believed it necessary to collect some additional data so that the trend could be affirmed or rejected for EGUs. If the trend were rejected, then EPA would be able to establish an emission limit for dioxin/furan; however, if the trend were affirmed, then EPA would need to seek alternatives to an emissions limit, such as a work practice standard. The latter approach might become necessary because measurements made at or below MDL generally indicate the presence, but not the exact quantity, of a substance. In addition, measurements made at or below the MDL have an accuracy on the order of plus or minus 50 percent, whereas other environmental measurements used by EPA in other rulemakings exhibit accuracies of plus or minus up to 15 percent. Sampling and analytical methods for dioxins/furans have improved since the 1990's work, so their MDLs are expected to have decreased. Moreover, for this sampling effort, we required sampling periods to be extended up to eight times longer than normal to collect more sample volume, thus, hopefully improving detection capability. Note that although longer sampling periods can be obtained during short term emissions testing, maintaining such longer sampling times

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[152] Although the combination of extended sampling times and stack chemistry for many units in this source category rendered the test method for HCN unreliable, yielding suspect HCN results, we still consider SO_2 or HCl emissions to be adequate surrogates for HCN emissions.

[153] Gullett, BK, *et al.* Effect of Cofiring Coal on Formation of Polychlorinated Dibenzo-*p*-Dioxins and Dibenzofurans during Waste Combustion. *Environmental Science and Technology.* Vol. 34, No. 2:282–290. 2000.

[154] Raghunathan, K, and Gullett, BK. Role of Sulfur in Reducing PCDD and PCDF Formation. *Environmental Science and Technology.* Vol. 30, No. 6:1827–1834. 1996.

[155] Li., H, *et al.* Chlorinated Organic Compounds Evolved During the combustion of Blends of Refuse-derived Fuels and Coals. *Journal of Thermal Analysis.* Vol. 49:1417–1422. 1997.

becomes impractical, if not infeasible, for continuous monitoring.

For these reasons, we selected 50 units at random from the entire coal-fired EGU population to conduct emission testing for dioxins/furans. EPA has identified AC as a potential control technology for dioxin/furan control based on results of previous work done on MWC units, and several of the units that were selected for testing have ACI systems that had been installed for Hg control. Specifics of the required testing may be found in Docket entry EPA–HQ–OAR–2009–0234–0062.

Emissions of CO, VOC, and/or THC have, in the past, been used as surrogates for the non-dioxin/furan organic HAP based on the theory that efficient combustion leads to lower organic emissions (Portland Cement NESHAP—THC (75 FR 54970; September 9, 2010); Boiler NESHAP—CO (75 FR 32005, June 4, 2010; 75 FR 31895, June 4, 2010 (proposed rules; the final rules were signed on February 21, 2011)); Hazardous Waste Combustor NESHAP—CO (64 FR 52828; September 30, 1999)). Although indications are that organic HAP emissions are low (and perhaps below the MDL), there were very few emissions data available for these compounds from coal-fired EGUs and we determined that it was necessary to obtain additional information on which to establish standards for these HAP. EPA identified the newest units as being representative of the most modern, and, thus, presumed most efficient units. The 170 newest units were selected and were required to test for CO, VOC, and THC; specifics of the required testing may be found in Docket entry EPA–HQ–OAR–2009–0234–0062.

Emissions of certain non-Hg metallic HAP (*i.e.,* Sb, Be, Cd, Cr, Co, Pb, Mn, and Ni) have been assumed to be well controlled by PM control devices. However, Hg and other non-Hg metallic HAP (*i.e.,* As and Se), have the potential to exist in both the particulate and vapor phases, and, therefore, may not be well controlled by PM control devices alone. Also, it has been shown through recent stack testing that certain of these HAP (*i.e.,* As and Se) may condense on (or as) very fine PM in the emissions from coal-fired units. There are very few recent emissions test data available showing the potential control of these metallic HAP from coal-fired EGUs.

EPA identified the units with the newest PM controls installed as the units to test for non-Hg metal HAP. EPA believed that these units represent those units having to comply with the most recent, and, therefore, likely most stringent, emission limits for PM. EPA believes units complying with stringent PM limits represent the top performers with regard to non-Hg metallic HAP emissions, even for those HAP that may at times form in other than the particulate phase. The units selected also included a number with ACI installed. The 170 units with the newest PM controls installed were selected and were required to test after that specific PM control (or at the stack if the PM control device is not shared with one or more other units); specifics of the required testing may be found in Docket entry EPA–HQ–OAR–2009–0234–0062.

The capture of Hg is dependent on several factors including the chloride content of the coal, the sulfur content of the coal, the amount of unburned carbon present in the fly ash, and the flue gas temperature profile. All of these factors affect the chemical form (the speciation) of Hg in the flue gas. Mercury may exist as Hg^0, as Hg^{+2} (or reactive gaseous Hg, RGM) or as Hg_p. Based on available data, EPA believes that sorbent injection (including ACI) has the potential to be a very effective technology for controlling Hg emissions in coal-fired plants, and some units using ACI for Hg control were among those selected for testing. EPA had no direct stack test results showing how effectively these ACI-equipped plants reduce their Hg emissions. The effectiveness of ACI is highly dependent upon the type of sorbent used (*i.e.,* chemically treated versus conventional AC) and on the amount injected. Further, previous data-gathering efforts had shown that FFs are capable of providing highly effective control of certain species of Hg and, in some cases, as high or higher than that achieved by ACI (ACI is not always used to achieve maximum reductions in Hg but, rather, to achieve permit requirements). Thus, testing for Hg was included with the testing for the non-Hg metallic HAP.

To be able to assess the impact of the standards (*e.g.,* reduction in HAP emissions over current conditions), EPA selected at random 50 units from the population of coal-fired units not selected in any of the above groups to test; specifics of the required testing may be found in Docket entry EPA–HQ–OAR–2009–0234–0062. We did not use the data gathered for the Utility Study because those data are outdated and lack sufficient detail. Thus, EPA believed that gathering these data was necessary to assess the emissions of this important source category.

All IGCC units were also required to test; specifics of the required testing may be found in Docket entry EPA–HQ–OAR–2009–0234–0062.

EPA was able to identify the best performing coal-fired units for the three HAP surrogate groups but the data obtained in support of the Utility Study and the December 2000 Finding do not indicate that any oil-fired units control beyond some ESP use and the data do not show any correlation between the PM control at oil-fired units and emissions of non-Hg metallic HAP from those units. Further, no oil-fired EGU has been constructed in decades and no oil-fired EGU has a FGD system installed, eliminating the potential basis for the use of compliance with an SO_2 emissions limit that resulted in the installation of an FGD system as a basis for selecting best performers for the acid-gas HAP from such units. Thus, EPA had no basis for determining which oil-fired units may be the "best performers." Therefore, EPA required that 66 units selected at random from the population of known oil-fired units test their stack emissions; specifics of the required testing may be found in Docket entry EPA–HQ–OAR–2009–0234–0062.

All petroleum coke-fired units identified were required to test; specifics of the required testing may be found in Docket entry EPA–HQ–OAR–2009–0234–0062.

Pursuant to CAA section 112(q)(3), CAA section 112 as in effect prior to the 1990 CAA amendments remains in effect for radionuclide emissions from coal-fired EGUs at the Administrator's discretion. For this reason, we did not require testing for radionuclides. We are also not proposing standards for radionuclides in this action.

F. What is the relationship between this proposed rule and other combustion rules?

1. CAA Section 111

Revised NSPS for SO_2, NO_X, and PM were promulgated under CAA section 111 for EGUs (40 CFR part 60, subpart Da) and industrial boilers (IB) (40 CFR part 60, subparts Db and Dc) on February 27, 2006 (71 FR 9866). As noted elsewhere, we are proposing certain amendments to 40 CFR part 60, subpart Da. In developing this proposed rule, we considered the monitoring requirements, testing requirements, and recordkeeping requirements of the existing NSPS to avoid duplicating requirements to the extent possible.

2. CAA Section 112

EPA has previously developed other non-EGU combustion-related NESHAP under CAA section 112(d) in addition to today's proposed rule for coal- and oil-fired EGUs. EPA signed final NESHAP for major and area source Boiler NESHAP on February 21, 2011 (to be codified at 40 CFR part 63, subpart DDDDD and subpart JJJJJJ, respectively) and promulgated standards for stationary combustion turbines (CT) on March 5, 2004 (69 FR 10512; 40 CFR part 63 subpart YYYY). In addition to these two NESHAP, on February 21, 2011, EPA also signed final CAA section 129 standards for commercial and institutional solid waste incinerator (CISWI) units, including energy recovery units (to be codified at 40 CFR part 60, subparts CCCC (NSPS) and DDDD (emission guidelines) and a definition of non-hazardous secondary materials that are solid waste (Non-hazardous Solid Waste Definition Rule, to be codified at 40 CFR part 241, subpart B). EGUs and IB that combust fossil fuel and solid waste, as that term is defined by the Administrator pursuant to the Resource Conservation and Recovery Act (RCRA), will be subject to section 129 (*e.g.,* CISWI energy recovery units), unless they meet one of the exemptions in CAA section 129(g). CAA section 129 standards are discussed in more detail below.

The two IB NESHAP, CT NESHAP, and this proposed rule will regulate HAP emissions from sources that combust fossil fuels for electrical power, process operations, or heating. The differences among these rules are due to the size of the units (MWe or Btu/hr), the boiler/furnace technology, or the portion of their electrical output (if any) for sale to any utility power distribution systems. *See* CAA section 112(a)(8) (defining EGU) earlier.

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.

The CT rule regulates HAP emissions from all simple-cycle and combined-cycle stationary CTs producing electricity or steam for any purpose. Because of their combustion technology, simple-cycle and combined-cycle stationary CTs (with the exception of IGCC units that burn gasified coal or petroleum coke syngas) are not considered EGUs for purposes of this proposed rule.

Any combustion unit, regardless of size, that produces steam to serve a generator that produces electricity exclusively for industrial, commercial, or institutional purposes (*i.e.,* no sales are made to the national electrical distribution grid) 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 an EGU under the proposed rule if the size of the combustion unit is less than or equal to 25 MWe. Units under that size would be subject to one of appropriate Boiler NESHAP. Further, EPA interprets the CAA section 112(a)(8) definition such that a non-cogeneration unit must both have a combustion unit of more than 25 MWe and supply more than 25 MWe to any utility power distribution system for sale to be considered an EGU pursuant to this proposed rule so as to be consistent with the cogeneration definition in CAA section 112(a)(8). Such units that sell less than 25 MWe of their power generation to the grid would be subject to the appropriate Boiler NESHAP.

As noted earlier, natural gas-fired EGU's were not included in the December 2000 listing. Thus, this proposed rule would not regulate a unit that otherwise meets the CAA section 112(a)(8) definition of an EGU but combusts natural gas exclusively or natural gas in combination with another fuel where the natural gas constitutes 90 percent or more of the average annual heat input during the previous 3 calendar years or 85.0 percent or more of the annual heat input during any one of those calendar years. Such units are considered to be natural gas-fired EGUs and would not be subject to this proposed rule.

The CAA does not define the terms "fossil fuel" and "fossil fuel fired;" therefore, we are proposing definitions for both terms. The definition of "fossil fuel fired" will determine the applicability of the proposed rule to combustion units that sell electricity to the utility power distribution system. A number of units that may otherwise meet the CAA section 112(a)(8) EGU definition fire primarily non-fossil fuels (*e.g.,* biomass). However, these units generally startup using either natural gas or oil and may use these fuels (or coal) during normal operation for flame stabilization. We have included a definition that will establish the scope of applicability based in part on the amount of fossil fuel combustion necessary to make a unit become "fossil fuel fired," and the units that combust primarily non-fossil fuel will be subject to this proposed rule should they fire more than that amount of coal or oil. Specifically, EPA is proposing that an EGU must be capable of combusting more than 73 MWe (250 MMBtu/hr) heat input[156] (equivalent to 25 MWe output) of coal or oil to be considered an EGU subject to this proposed rule. To be "capable of combusting" coal or oil, a unit would need to have fossil fuels allowed in their permits and have the appropriate fuel handling facilities on-site (*e.g.,* coal handling equipment, including for purposes of example, but not limited to, coal storage area, belts and conveyers, pulverizers, *etc.;* oil storage facilities). In addition, EPA is proposing that an EGU must have fired coal or oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years to be considered a fossil fuel-fired EGU subject to this proposed rule. Units that do not meet these definitions would, in most cases, be considered IB units subject to one of the Boiler NESHAP. Thus, for example, a biomass-fired EGU, regardless of size, that utilizes fossil fuels for startup and flame stabilization purposes only (*i.e.,* less than or equal to 250 MMBtu/hr and used less than 10.0 percent of the average annual heat input during the previous 3 calendar years or less than 15.0 percent of the annual heat input during any one of those calendar years) is not considered to be a fossil fuel-fired EGU under this proposed rule. EPA has based its threshold value on the definition of "oil-fired" in the ARP found at 40 CFR 72.2. As EPA has no data on such use for (*e.g.*) biomass co-fired EGUs because their use has not yet become commonplace, we believe this definition also accounts for the use of fossil fuels for flame stabilization use without inappropriately subjecting such units to this proposed rule. EPA solicits comment on the use of these definitions. Commenters suggesting alternate definitions (including thresholds) should provide detailed information in support of their comment (*e.g.,* 3- to 5-year average fossil fuel use under conditions of startup and flame stabilization).

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 EGU if it is fossil fuel fired as that term is defined above. For such units, EPA is proposing that the unit must be capable of combusting sufficient coal or oil to generate 25 MWe from the fossil fuel alone, and must provide for sale to any utility power distribution system electricity equal to

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[156] Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and IB).

more than one-third of their potential electric output capacity and greater than 25 MWe electrical output. However, a cogeneration facility that meets the above definition of an EGU during any portion of a month would be subject to the proposed EGU rule for the succeeding 6 calendar months (combustion units that begin combusting solid waste must immediately comply with an applicable CAA section 129 standard (*e.g.,* CISWI standards applicable to energy recovery units)).

We recognize that different section 112 rules may impact a particular unit at different times. For example there will likely be some cogeneration units that are determined to be covered under the Boiler NESHAP. Such unit may make a decision to increase/decrease the proportion of production output being supplied to the electric utility grid, thus causing the unit to meet the EGU cogeneration criteria (i.e., greater than one-third of its potential output capacity and greater than 25 MWe). A unit subject to one of the Boiler NESHAP that increases its electricity output and meets the definition of an EGU would be subject to the proposed EGU NESHAP for the 6-month period after the unit meets the EGU definition. Assuming the unit did not meet the definition of an EGU following that initial occurrence, at the end of the 6-month period it would revert back to being subject to the Boiler NESHAP. This approach is consistent with that taken on the CISWI rulemaking.

EPA solicits comment on the extent to which this situation might occur and whether the 6-month period is appropriate. Given the differences between the rules, should EPA address reclassification of the sources between the rules, particularly with regard to initial and ongoing compliance requirements and schedules? (As noted above, EPA is proposing to consider as an EGU any cogeneration unit that meets the definition noted earlier during any month in a year.) We specifically solicit comments as to how to address sources that may meet the definition of an EGU for only parts of a year. We also solicit comment on whether we should include provisions similar to those included in the final CISWI rule to address units that combust different fuels at different times. See Final CISWI Rule, 40 CFR 60.2145, *http://www.epa.gov/airquality/combustion/docs/20110221ciswi.pdf.*

Another situation may occur where one or more coal- or oil-fired EGU(s) share an air pollution control device (APCD) and/or an exhaust stack with one or more similarly-fueled IB unit(s). 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 this proposed rule or the final Boiler NESHAP. Therefore, EPA is proposing that compliance with the more stringent emission limit be demonstrated.

EPA solicits comment on the extent to which this situation might occur. Given potential differences between the rules, how should EPA address apportionment of the emissions to the individual sources with regard to initial and ongoing compliance requirements? 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.

3. CAA Section 129

Units that combust "non-hazardous solid waste" as defined by the Administrator under RCRA are regulated under the provisions of CAA section 129. On February 21, 2011, EPA signed the final Non-Hazardous Solid Waste Definition Rule. Any EGU that combusts any solid waste as defined in that final rule is a solid waste incineration unit subject to CAA section 129.

In the Non-Hazardous Solid Waste Definition Rule, EPA determined that coal refuse from current mining operations is not considered to be a "solid waste" if it is not discarded. Coal refuse that is in legacy coal refuse piles is considered a "solid waste" because it has been discarded. However, if the discarded coal refuse is processed in the same manner as currently mined coal refuse, the coal refuse would not be a solid waste and, therefore, the combustion of such material would not subject the unit to regulation under CAA section 129. By contrast, the unit would be subject to this rule if it meets the definition of EGU. If the unit combusts solid waste, it would be subject to emission standards under CAA section 129. *See, e.g.,* CISWI rule. Coal refuse properly processed is a product fossil fuel (*i.e.,* not a solid waste) if it is not a solid waste; thus, combustion units that otherwise meet the CAA section 112(a)(8) EGU definition that combust coal refuse that is product fuel not a solid waste are EGUs subject to this proposed rule. For this proposed rule, we assumed that all units that combust coal refuse and otherwise meet the definition of a coal-fired EGU combust newly mined coal refuse or coal refuse from legacy piles that has been processed such that it is not a solid waste. We request comment on this assumption and whether there are any units combusting coal refuse that is a solid waste such that the units would be solid waste incineration units instead of EGUs.

Further, CAA section 129(g)(1)(B) exempts from regulation under CAA section 129

> "* * * qualifying small power production facilities, as defined in section 796(17)(C) of Title 16, or qualifying cogeneration facilities, as defined in section 796(18)(B) of Title 16, which burn homogeneous waste * * * for the production of electric energy or in the case of qualifying cogeneration facilities which burn homogeneous waste for the production of electric energy and steam or other forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes * * *"

Thus, qualifying small power production facilities and cogeneration facilities that burn a homogeneous waste would be exempt from regulation under CAA section 129. If the "homogeneous waste" material combusted is a fossil fuel, then the units that are exempt from regulation under CAA section 129 and that otherwise meet the definition of an EGU under CAA section 112(a)(8) would be covered under this proposed rule. For example, a unit that combusts only coal refuse that is a solid waste would be subject to this proposed rule if the unit met the definition of EGU and the coal refuse was determined to be a "homogenous waste" as that term is defined in the final CAA section 129 CISWI standards (the final rule was signed on February 21, 2011, but has not yet been published in the **Federal Register**).

G. What emission limitations and work practice standards must I meet?

We are proposing the emission limitations presented in Tables 10 and 11 of this preamble. Within the two major subcategories of "coal" and "oil," emission limitations were developed for new and existing sources for five subcategories, two for coal-fired EGUs, one for coal- and solid oil-derived IGCC EGUs, and two for oil-fired EGUs, which we developed based on unit type.

We are proposing that new or existing EGUs are "coal-fired" if they combust coal and meet the proposed definition of "fossil fuel fired." We are proposing that an EGU is considered to be a "coal-fired unit designed for coal greater than or equal to 8,300 Btu/lb" if the EGU: (1) Combusts coal; (2) meets the proposed definition of "fossil fuel fired;" and (3) burns any coal in an EGU designed to burn a coal having a calorific value (moist, mineral matter-free basis) of greater than or equal to 19,305 kilojoules per kilogram (kJ/kg) (8,300 British thermal units per pound (Btu/lb)) in an EGU with a height-to-depth ratio of less than 3.82. We are proposing that the EGU is considered to be a "coal-fired unit designed for coal less than 8,300 Btu/lb" if the EGU: (1) Combusts coal; (2) meets the proposed definition of "fossil fuel fired;" and (3) burns any virgin coal in an EGU designed to burn a nonagglomerating fuel having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) in an EGU with a height-to-depth ratio of 3.82 or greater.

We are proposing that the EGU is considered to be an IGCC unit if the EGU: (1) Combusts gasified coal or solid oil-derived (*e.g.,* petroleum coke); (2) meets the proposed definition of "fossil fuel fired;" and (3) is classified as an IGCC unit. We are not proposing to subcategorize IGCC EGUs based on the source of the syngas used (*i.e.,* coal, petroleum coke). Based on information available to the Agency, although the fuel characteristics of coal and petcoke are quite different, the syngas products are very similar from both feedstocks.[157]

We are proposing that the EGU is considered to be "liquid oil" fired if the EGU burns liquid oil and meets the proposed definition of "fossil fuel fired." We are proposing that the EGU is considered to be "solid oil-derived fuel-fired" if the EGU burns any solid oil-derived fuel (*e.g.,* petroleum coke) and meets the proposed definition of "fossil fuel fired." EPA is also considering a limited-use subcategory to account for liquid oil-fired units that only operate a limited amount of time per year on oil and are inoperative the remainder of the year. Such units could have specific emission limitations, reduced monitoring requirements (limited operation may preclude the ability to conduct stack testing), or be held to the same emission limitations (which could be met through fuel sampling) as other liquid oil-fired units. EPA solicits comment on all of these proposed subcategorization approaches.

TABLE 10—EMISSION LIMITATIONS FOR COAL-FIRED AND SOLID OIL-DERIVED FUEL-FIRED EGUS

Subcategory	Total particulate matter	Hydrogen chloride	Mercury
Existing coal-fired unit designed for coal ≥ 8,300 Btu/lb.	0.030 lb/MMBtu (0.30 lb/MWh)	0.0020 lb/MMBtu (0.020 lb/MWh).	1.0 lb/TBtu (0.0.008 lb/GWh).
Existing coal-fired unit designed for coal < 8,300 Btu/lb.	0.030 lb/MMBtu (0.30 lb/MWh)	0.0020 lb/MMBtu (0.020 lb/MWh).	11.0 lb/TBtu (0.20 lb/GWh) 4.0 lb/TBtu * (0.040 lb/GWh *).
Existing—IGCC	0.050 lb/MMBtu (0.30 lb/MWh)	0.00050 lb/MMBtu (0.0030 lb/MWh).	3.0 lb/TBtu (0.020 lb/GWh).
Existing—Solid oil-derived	0.20 lb/MMBtu (2.0 lb/MWh)	0.0050 lb/MMBtu (0.080 lb/MWh).	0.20 lb/TBtu (0.0020 lb/GWh).
New coal-fired unit designed for coal ≥8,300 Btu/lb.	0.050 lb/MWh	0.30 lb/GWh	0.000010 lb/GWh.
New coal-fired unit designed for coal <8,300 Btu/lb.	0.050 lb/MWh	0.30 lb/GWh	0.040 lb/GWh.
New—IGCC	0.050 lb/MWh *	0.30 lb/GWh *	0.000010 lb/GWh *.
New—Solid oil-derived	0.050 lb/MWh	0.00030 lb/MWh	0.0020 lb/GWh.

Note: lb/MMBtu = pounds pollutant per million British thermal units fuel input.
lb/TBtu = pounds pollutant per trillion British thermal units fuel input.
lb/MWh = pounds pollutant per megawatt-electric output (gross).
lb/GWh = pounds pollutant per gigawatt-electric output (gross).
* Beyond-the-floor limit as discussed elsewhere.

TABLE 11—EMISSION LIMITATIONS FOR LIQUID OIL-FIRED EGUS

Subcategory	Total HAP metals *	Hydrogen chloride	Hydrogen fluoride
Existing—Liquid oil	0.000030 lb/MMBtu (0.00030 lb/MWh)	0.00030 lb/MMBtu (0.0030 lb/MWh)	0.00020 lb/MMBtu. (0.0020 lb/MWh).
New—Liquid oil	0.00040 lb/MWh	0.00050 lb/MWh	0.00050 lb/MWh.

* Includes Hg.

Pursuant to CAA section 112(h), we are proposing a work practice standard for organic HAP, including emissions of dioxins and furans, from all subcategories of EGU. The work practice standard being proposed for these EGUs would require the implementation of an annual performance (compliance) test program as described elsewhere in this preamble. We are proposing work practice standards because the data confirm that the significant majority of the measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units. As discussed later in this preamble, EPA believes the inaccuracy of a majority of measurements coupled with the extended sampling times used, fulfill the criteria for these HAP to be subject to a work practice standard under CAA section 112(h).

We are proposing a beyond-the-floor standard for Hg only for all existing coal-fired units designed for coal less than 8,300 Btu/lb based on the use of ACI for Hg control, as described elsewhere in this preamble. We are proposing a beyond-the-floor standard for all pollutants for new IGCC units based on the new-source limits for coal-fired units designed for coal greater than or equal to 8,300 Btu/lb as described elsewhere in this preamble.

As noted elsewhere in this preamble, we are proposing to use total PM as a surrogate for the non-Hg metallic HAP and HCl as a surrogate for the acid gas HAP for all subcategories of coal-fired EGUs and for the solid oil derived fuel-fired EGUs. For liquid oil-fired EGUs, we are proposing total HAP metal, HCl, and HF emission limitations.

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[157] U.S. Department of Energy, Wabash River Coal Gasification Repowering Project. Project Performance Summary; Clean Coal Technology Demonstration Program. DOE/FE–0448. July 2002.

In addition, we are proposing three alternative standards for certain subcategories: (1) SO_2 (as an alternative equivalent to HCl for all subcategories with add-on FGD systems); (2) individual non-Hg metallic HAP (as an alternate to PM for all subcategories except liquid oil-fired); (3) total non-Hg metallic HAP (as an alternate to PM for all subcategories except liquid oil-fired); and (4) individual metallic HAP (as an alternate to total metal HAP) for the liquid oil-fired subcategory. These alternative proposed standards are discussed elsewhere in this preamble.

H. What are the startup, shutdown, and malfunction (SSM) requirements?

The DC Circuit Court vacated portions of two provisions in EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. *Sierra Club* v. *EPA,* 551 F.3d 1019 (DC Cir. 2008), cert. denied, 130 S. Ct. 1735 (U.S. 2010). Specifically, the DC Circuit Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), that are part of a regulation, commonly referred to as the "General Provisions Rule," that EPA promulgated under CAA section 112. When incorporated into CAA section 112(d) regulations for specific source categories, these two provisions exempt sources from the requirement to comply with the otherwise applicable CAA section 112(d) emission standard during periods of SSM.

Consistent with *Sierra Club,* EPA is proposing standards in this rule that apply at all times. In proposing the standards in this rule, EPA has taken into account startup and shutdown periods and, for the reasons explained below, has not proposed different standards for those periods. The standards that we are proposing are 30 boiler operating day averages. EGUs, especially solid fuel-fired EGUs, do not normally startup and shutdown frequently and typically use cleaner fuels (*e.g.,* natural gas or oil) during the startup period. Based on the data before the Agency, we are not establishing different emissions standards for startup and shutdown.

To appropriately determine emissions during startup and shutdown and account for those emissions in assessing compliance with the proposed emission standards, we propose use of a default diluent value of 10.0 percent O_2 or the corresponding fuel specific CO_2 concentration for calculating emissions in units of lb/MMBtu or lb/TBtu during startup or shutdown periods. For calculating emissions in units of lb/MWh or lb/GWh, we propose source owners use an electrical production rate of 5 percent of rated capacity during periods of startup or shutdown. We recognize that there are other approaches for determining emissions during periods of startup and shutdown, and we request comment on those approaches. We further solicit comment on the proposed approach described above and whether the values we are proposing are appropriate.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *." 40 CFR 63.2. EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times. In *Mossville Environmental Action Now* v. *EPA,* 370 F.3d 1232, 1242 (DC Cir. 2004), the DC Circuit Court upheld as reasonable standards that had factored in variability of emissions under all operating conditions. However, nothing in CAA section 112(d) or in case law requires that EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. *See, Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (DC Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.")

Further, it is reasonable to interpret CAA section 112(d) as not requiring EPA to account for malfunctions in setting emissions standards. For example, we note that CAA section 112 uses the concept of "best performing" sources in defining MACT, the level of stringency that major source standards must meet. Applying the concept of "best performing" to a source that is malfunctioning presents significant difficulties. The goal of best performing sources is to operate in such a way as to avoid malfunctions of their units.

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 112(d) standards for EGUs. As noted above, by definition, malfunctions are sudden and unexpected events and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in the category. Moreover, malfunctions can vary in frequency, degree, and duration, further complicating standard setting.

In the unlikely event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to reduce the likelihood that malfunctions would occur, minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." *See* 40 CFR 63.2 (definition of malfunction).

Finally, EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.,* State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (September 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (February 15, 1983)). EPA is, therefore, proposing an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. *See* 40 CFR 63.10042 (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also are proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in section 63.10001. *See* 40 CFR 22.24. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and/or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *." The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 63.10000(b) and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *" and that "[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *" In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113. *See* also 40 CFR part 22.77.

I. What are the testing requirements?

We are proposing that the owner or operator of a new or existing coal- or oil-fired EGU must conduct performance tests to demonstrate compliance with all applicable emission limits. For units using certified continuous emissions monitoring systems (CEMS) that directly measure the concentration of a regulated pollutant under proposed 40 CFR part 63, subpart UUUUU (*e.g.,* Hg CEMS, SO_2 CEMS, or HCl CEMS) or sorbent trap monitoring systems, the initial performance test would consist of all valid data recorded with the certified monitoring system in the first 30 operating days after the compliance date. For units using CEMS to measure a surrogate for a regulated pollutant (*i.e.,* PM CEMS), initial stack testing of the surrogate and the regulated pollutant conducted during the same compliance test period and under the same process (*e.g.,* fuel) and control device operating conditions would be required, and an operating limit would be established. Affected units would be required to conduct the following compliance tests where applicable:

(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, if you elect to comply with the total PM emission limit, then you would conduct HAP metals and PM emissions testing during the same compliance test period and under the same process (*e.g.,* fuel) and control device operating conditions initially and every 5 years using EPA Methods 29, 5, and 202. Continuous compliance would be determined using a PM CEMS with an operating limit established based on the filterable PM values measured using Method 5. If you elect to comply with the total HAP metals emission limit or the individual HAP metals emissions limits, then you would conduct total PM and HAP metals testing during the same compliance test period and under the same process (*e.g.,* fuel) and control device operating conditions at least once every 5 years and, to demonstrate continuous compliance, you would conduct total or individual HAP metals emissions testing every 2 months (or every month if you have no PM control device) using EPA Method 29. Note that the filter temperature for each Method 29 or 5 emissions test is to be maintained at 160 ± 14 °C (320 ± 25 °F) and that the material in Method 29 impingers is to be analyzed for metals content.

(2) Coal-fired, IGCC, and solid oil-derived fuel-fired units would be required to use a Hg CEMS or sorbent trap monitoring system for continuous compliance using the continuous Hg monitoring provisions of proposed Appendix A to proposed 40 CFR part 63, subpart UUUUU. The initial performance test would consist of all valid data recorded with the certified Hg monitoring system in the first 30 boiler operating days after the compliance date.

(3) For coal-fired and solid oil-derived fuel-fired units and new or reconstructed IGCC units that have SO_2 emission controls and elect to use SO_2 CEMS for continuous compliance, an initial stack test for SO_2 would not be required. Instead the first 30 days of SO_2 CEMS data would be used to determine initial compliance. For units with or without SO_2 or HCl emission controls that elect to use HCl CEMS, an initial stack test for HCl would not be required. Instead the first 30 days of HCl CEMS data would be used to determine initial compliance. For units without HCl CEMS and without SO_2 or HCl emissions control devices, you would be required to conduct HCl emissions testing every month using EPA Method 26 if no entrained water droplets exist in the exhaust gas or Method 26A if entrained water droplets exist in the exhaust gas. For units without SO_2 or HCl CEMS but with SO_2 emissions control devices, you would conduct HCl testing at least every 2 months using EPA Method 26 or 26A. For units without SO_2 or HCl CEMS and without SO_2 emissions control devices, you would conduct HCl emissions testing every month using EPA Method 26A if entrained water droplets exist in the exhaust gas or Method 26A or 26 if no entrained water droplets exist in the exhaust gas.

(4) For all required performance stack tests, you would conduct concurrent oxygen (O_2) or carbon dioxide (CO_2) emission testing using EPA Method 3A and then, use an appropriate equation, selected from among Equations 19–1 through 19–9 in EPA Method 19 to convert measured pollutant concentrations to lb/MMBtu values. Multiply the lb/MMBtu value by one million to get the lb/TBtu value (if applicable).

(5) For liquid oil-fired units, initial performance testing would be conducted as follows. For non-Hg HAP metals, use EPA Method 29. For Hg, conduct emissions testing using EPA Method 29 or Method 30B. For acid gases, conduct HCl and HF testing using EPA Methods 26A or 26. Conduct additional performance testing for Hg at least annually; conduct additional performance tests for HAP metals and acid gases every 2 months if the EGU has emission controls for metals or acid gases, and every month if the EGU does not have these controls.

(6) For existing units that qualify as low emitting EGUs (LEEs), conduct subsequent performance tests for the LEE qualified pollutants every 5 years and perform fuel analysis monthly.

Except for liquid oil-fired units, those EGUs with PM emissions control devices, without HCl CEMS but with HCl control devices, or for LEE, we are proposing that you monitor during initial performance testing specified operating parameters that you would use to demonstrate ongoing compliance. You would calculate the minimum (or maximum, depending on the parameter measured) hourly parameter values measured during each run of a 3-run performance test. The average of the three minimum (or maximum) values from the three runs for each applicable parameter would establish a site-specific operating limit. The applicable operating parameters for which operating limits would be required to be established are based on the emissions limits applicable to your unit as well as the types of add-on controls on the unit. The following is a summary of the operating limits that we are proposing to be established for the various types of the following units:

(1) For units without wet or dry FGD scrubbers that must comply with an HCl emission limit, you must measure the average chlorine content level in the input fuel(s) during the HCl performance test. This is your maximum chlorine input operating limit.

(2) For units with wet FGD scrubbers, you must measure pressure drop and liquid flow rate of the scrubber during the performance test, and determine the maximum value for each test run. The average of the minimum hourly value for the three test runs establishes your minimum site-specific pressure drop and liquid flow rate operating levels. If different average parameter levels are measured during the Hg and HCl tests, the highest of the average values becomes your site-specific operating limit. If you are complying with an HCl emission limit, you must measure pH of the scrubber effluent during the performance test for HCl and determine the minimum hourly value for each test run. The average of the three minimum hourly values from the three test runs establishes your minimum pH operating limit.

(3) For units with dry scrubbers or DSI (including ACI), you would be required to measure the sorbent injection rate for each sorbent used during the performance tests for HCl and Hg and determine the minimum hourly rate of injected sorbent for each test run. The average of the three test run minimum values established during the performance tests would be your site-specific minimum sorbent injection rate operating limit. If different sorbents and/or injection rates are used during the Hg and HCl performance testing, the highest value for each sorbent becomes your site-specific operating limit for the respective HAP. If the same sorbent is used during the Hg and HCl performance testing, but at different injection rates, the highest average value for each sorbent becomes your site-specific operating limit. The type of sorbent used (*e.g.,* conventional AC, brominated AC, trona, hydrated lime, sodium carbonate, etc.) must be specified.

(4) For units with FFs in combination with wet scrubbers, you must measure the pH, pressure drop, and liquid flow rate of the wet scrubber during the performance test and calculate the minimum hourly value for each test run. The average of the minimum hourly values from the three test runs establishes your site-specific pH, pressure drop, and liquid flow rate operating limits for the wet scrubber.

(5) For units with an ESP in combination with wet scrubbers, you must measure the pH, pressure drop, and liquid flow rate of the wet scrubber during the HCl performance test and you must measure the voltage and current of each ESP collection field during the Hg and PM performance test. You would then be required to calculate the minimum hourly value of these parameters for each of the three test runs. The average of the three minimum hourly values would establish your site-specific minimum pH, pressure drop, and liquid flow rate operating limit for the wet scrubber and the minimum voltage and current operating limits for the ESP.

(6) For liquid oil-fired or LEEs, you would be required to measure the Hg, Cl, and HAP metal content of the inlet fuel that was burned during the Hg, HCl and HF, and HAP metal emissions performance testing. The fuel content value for each of these compounds is your maximum fuel inlet operating limit for each of these compounds.

(7) For units with FFs, you must measure the output of the bag leak detection system (BLDS) sensor (whether in terms of relative or absolute PM loading) during each Hg, PM, and metals performance test. You would then be required to calculate the minimum hourly value of this output for each test run. The average of the minimum hourly BLDS values would establish your site-specific maximum BLDS sensor output and current operating limit for the BLDS.

(8) For units with an ESP, you must measure the voltage and current of each ESP collection field during each Hg, PM, and metals performance test. You would then be required to calculate the minimum hourly value of these parameters for each test run. The average of the three minimum hourly values would establish your site-specific minimum voltage and current operating limits for the ESP.

(9) Note that you establish the minimum (or maximum) hourly average operating limits based on measurements done during performance testing; should you desire to have differing operating limits which correspond to other loads, you should conduct testing at those other loads to determine those other operating limits.

Instead of operating limits for dioxins and furans and non-dioxin/furan organic HAP, we are proposing that owners or operators of units submit documentation that a "tune up" meeting the requirements of the proposed rule was conducted. Such a "tune-up" would require the owner or operator of a unit to:

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, but you must inspect each burner at least once every 18 months);

(2) Inspect the flame pattern, as applicable, and make any adjustments to the burner necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly;

(4) Optimize total emissions of CO and NO_X. This optimization should be consistent with the manufacturer's specifications, if available;

(5) Measure the concentration in the effluent stream of CO and NO_X in ppm, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made); and

(6) Maintain on-site and submit, if requested by the Administrator, an annual report containing:

(i) The concentrations of CO and NO_X in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after the adjustments of the EGU;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type and amount of fuel used over the 12 months prior to the adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period.

Many, if not most, EGUs have planned annual outages, and the inspection and tune up procedure was designed to occur during this normal occurrence. Nonetheless, we are proposing a maximum period of up to 18 months between inspections and tune ups to account for those EGUs with unusual planned outage schedules. We seek comment on the appropriateness of this period.

J. What are the continuous compliance requirements?

1. Continuous Compliance Requirements

To demonstrate continuous compliance with the emission limitations, we are proposing the following requirements:

(1) For IGCC units or units combusting coal or solid oil-derived fuel and electing to use PM as a surrogate for non-Hg HAP metals, you would install, certify, and operate PM CEMS in

accordance with Performance Specification (PS) 11 in Appendix B to 40 CFR part 60, and to perform periodic, on-going quality assurance (QA) testing of the CEMS according to QA Procedure 2 in Appendix F to 40 CFR part 60. An operating limit (PM concentration) would be set during performance testing for initial compliance; the hourly average PM concentrations would be averaged on a rolling 30 boiler operating day basis. Each 30 boiler operating day average would have to meet the PM operating limit.

IGCC units or units combusting coal or solid oil-derived fuel and electing to comply with the total non-Hg HAP metals emissions limit, would demonstrate continuous compliance by conducting Method 29 testing every two months if PM controls are installed or every month if no PM controls are installed. As an option, PM CEMS could be used to demonstrate continuous compliance as described above. IGCC units or units combusting coal or solid oil-derived fuel and electing to comply with the individual non-Hg HAP metals emissions limits, would have the option to demonstrate continuous compliance only by conducting Method 29; again, testing would be conducted every two months if PM controls are installed or every month if no PM controls are installed. IGCC units or units combusting coal or solid oil-derived fuel with PM controls but not using PM CEMS to demonstrate continuous compliance would also be required to conduct parameter monitoring and meet operating limits established during performance testing. Units using FFs would be required to install and operate BLDS. As mentioned earlier, the BLDS output would be required to be less than or equivalent with the average BLDS output determined during performance testing. Moreover, a source owner or operator would be required to operate the FFs such that the sum duration of alarms from the BLDS would not exceed 5 percent of the process operating time during any 6-month period. Units using an ESP would be required to install and operate sensors to detect and measure current and voltage for each field in the ESP. As mentioned earlier, the current and voltage values for each field in the ESP would need to be greater than or equivalent with the maximum test run averages determined during performance testing.

(2) For IGCC units or units combusting coal or solid oil-derived fuel, we are proposing that Hg CEMS or sorbent trap monitoring systems be installed, certified, maintained, operated, and quality-assured in accordance with proposed Appendix A to 40 CFR part 63, subpart UUUUU, and that Hg levels (averaged on a rolling 30 boiler operating day basis) be maintained at or below the applicable Hg emissions limit. Given that the proposed Appendix A QA procedures for Hg CEMS are based on a Hg emissions trading rule (CAMR), and this proposal is for a not-to-exceed NESHAP, EPA solicits comments on whether these Hg CEMS QA procedures should be adjusted. Further, we are proposing that each pair of sorbent traps be used to collect Hg samples for no more than 14 operating days, and that the traps be replaced in a timely manner to ensure that Hg emissions are sampled continuously. In requiring continuous Hg monitoring, we assumed that most, if not all, of the units that were subject to CAMR purchased Hg CEMS and/or sorbent trap systems prior to the rule vacatur, and that many of these monitoring systems are currently installed and in operation. The Agency's conclusion regarding Hg CEMS purchases and installation is based in part on the significant number of units (over 100) that voluntarily opted to submit Hg CEMS data for the 2010 ICR. We also considered the steps taken by the industry to prepare for CAMR, and the fact that many state regulations currently require the installation and operation of Hg CEMS in order to demonstrate compliance with various SIP and consent decrees.

(3) For new or reconstructed IGCC units or coal-fired or solid oil-derived fuel-fired units with SO_2 emissions control devices, we are proposing two compliance options for acid gases. First, an SO_2 or an HCl CEMS could be installed and certified. We are proposing that the SO_2 monitor be certified and quality-assured according to 40 CFR part 75 or PS 2 or 6 and Procedure 1 in Appendices B and F, respectively, of 40 CFR part 60. We believe this is reasonable, because nearly all utility units are subject to the ARP, and coal-fired ARP units already have certified SO_2 monitors in place that meet Part 75 requirements. For HCl monitors, PS 15 or 6 in Appendix B to 40 CFR part 60 would be used for certification and, tentatively, Procedure 1 of Appendix F to 40 CFR part 60 would be followed for on-going QA.

Note that a PS specific to HCl CEMS has not been promulgated yet, but we expect to publish one prior to the compliance date of this proposed rule and to make it available to source owners and operators. In the meantime, the FTIR CEMS (PS 15) may be an appropriate choice for measuring continuous HCl concentrations. Hourly data from the SO_2 or HCl monitor would be converted to the units of the emission standard and averaged on a rolling 30 boiler operating day basis. Each 30 boiler operating day average would have to meet the applicable SO_2 or HCl limit.

The second option that we are proposing would be for units without SO_2 or HCl CEMS but with SO_2 emissions control devices. For these units, parameter operating limits, established during performance testing, would be monitored continuously, along with the already-mentioned frequent (every 2 months) HCl emissions testing. For units with wet FGD scrubbers, we are proposing that you monitor pressure drop and liquid flow rate of the scrubber continuously and maintain 12-hour block averages at or above the operating limits established during the performance test. You must monitor the pH of the scrubber and maintain the 12-hour block average at or above the operating limit established during the performance test to demonstrate continuous compliance with the HCl emission limits.

For units with dry scrubbers or DSI systems, we are proposing that you continuously monitor the sorbent injection rate and maintain it at or above the operating limits established during the performance tests.

(4) For liquid oil-fired units, we are proposing to require testing as follows. HAP metals testing would be performed every other month if a unit has a non-Hg HAP metals control device, and every month if the unit does not have a non-Hg metals control device. We propose to require HCl and HF testing every other month if a unit has HCl and HF control devices, and monthly if the unit does not have these emissions controls.

(5) For each unit using PM, HCl, SO_2, or Hg CEMS for continuous compliance, we are proposing that you install, certify, maintain, operate and quality-assure the additional CEMS (*e.g.,* CEMS that measure oxygen or CO_2 concentration, stack gas flow rate, and moisture content) needed to convert pollutant concentrations to units of the emission standards or operating limits. Where appropriate, we have proposed that these additional CEMS may be certified and quality-assured according to 40 CFR part 75. Once again, we believe this is reasonable because almost all coal-fired utility units already have these monitors in place, under the ARP.

(6) For limited-use liquid oil combustion units, we are proposing that those units be allowed to demonstrate compliance with the Hg emission limit, the HAP metals, or the HCl and HF emissions limits separately or in

combination based on fuel analysis rather than performance stack testing, upon request by you and approval by the Administrator. Such a request would require the owner/operator to follow the requirements in 40 CFR 63.8(f), which presents the procedure for submitting a request to the Administrator to use alternative monitoring, and, among other things, explain why a unit should be considered for eligibility, including, but not limited to, use over the previous 5 years and projected use over the next 5 years. Approval from the Administrator would be required before you could use this alternative monitoring procedure. If approval were granted by the Administrator, we are proposing that you would maintain fuel records that demonstrate that you burned no new fuels or fuels from a new supplier such that the Hg, the non-Hg HAP metal, the fluorine, or the chlorine content of the inlet fuel was maintained at or below your maximum fuel Hg, non-Hg HAP metal, fluorine, or chlorine content operating limit set during the performance stack tests. If you plan to burn a new fuel, a fuel from a new mixture, or a new supplier's fuel that differs from what was burned during the initial performance tests, then you must recalculate the maximum Hg, HAP metal, fluorine, and/or chlorine input anticipated from the new fuels based on supplier data or own fuel analysis, using the methodology specified in Table 6 of this proposed rule. If the results of recalculating the inputs exceed the average content levels established during the initial test then, you must conduct a new performance test(s) to demonstrate continuous compliance with the applicable emission limit.

(7) For existing LEEs, we are proposing that those units that qualify be allowed to demonstrate continuous compliance with the Hg emission limit, the non-Hg HAP metals, or the HCl emissions limits separately or in combination based on fuel analysis rather than performance stack testing. LEE would be those units where performance testing demonstrates that emissions are less than 50 percent of the PM or HCl emissions limits, less than 10 percent of the Hg emissions limits, or less than 22.0 pounds per year (lb/yr) of Hg. Note that for LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volumes shown in Table 2 or this proposed rule must be increased nominally by a factor of two. The LEE cutoff of 22.0 lb/yr represents about 5 percent of the nationwide Hg mass emissions from the coal-fired units represented in the 2010 ICR. Most of the units that emit less than 22.0 lb/yr would be smaller units with relatively low heat input capacities. The 22.0 lb/yr threshold was determined by summing the total Hg emissions from the 1,091 units in operation and determining the 5th percentile of the total mass. The units were then ranked by their annual Hg mass emissions. At the point in the rankings where the cumulative mass was equivalent to the 5th percentile value calculated, the annual mass emissions of that unit (22.0 lb/yr) was selected as the threshold. Five percent of the total mass was chosen as a cut point because comments received on CAMR indicated that 5 percent of the total mass was a reasonable cut point. At this 5th percentile threshold, approximately 394 smaller units out of the 1,091 total units would have the option of using this Hg monitoring methodology.

Under the proposed alternative compliance option, you would maintain fuel records that demonstrate that you burned no new fuels or fuels from a new supplier such that the Hg, non-Hg HAP metal, or the chlorine content of the inlet fuel was maintained at or below your maximum fuel Hg, non-Hg HAP metal, fluorine, or chlorine content operating limit set during the performance stack tests. If you plan to burn a new fuel, a fuel from a new mixture, or a new supplier's fuel that differs from what was burned during the initial performance tests, then you must recalculate the maximum Hg, non-Hg HAP metal, and/or the maximum chlorine input anticipated from the new fuels based on supplier data or own fuel analysis, using the methodology specified in Table 6 of this proposed rule. If the results of recalculating the inputs exceed the average content levels established during the initial test then, you must conduct a new performance test(s) to demonstrate continuous compliance with the applicable emission limit.

(8) For all EGUs, we are proposing that you maintain daily records of fuel use that demonstrate that you have burned no materials that are considered solid waste.

If an owner or operator would like to use a control device other than the ones specified in this section to comply with this proposed rule, the owner/operator should follow the requirements in 40 CFR 63.8(f), which establishes the procedure for submitting a request to the Administrator to use alternative monitoring.

2. Streamlined Approach to Continuous Compliance

EPA is proposing to simplify compliance with the proposed rule by harmonizing its monitoring and reporting requirements, to the extent possible, with those of 40 CFR part 75. With a few exceptions, the utility industry is already required to monitor and report hourly emissions data according to Part 75 under the Title IV ARP and other emissions trading programs. The Agency is, therefore, proposing Hg monitoring requirements that are consistent with Part 75 and similar to those that had been promulgated for the vacated CAMR regulation. We are proposing that hourly Hg emission data be reported to EPA electronically, on a quarterly basis. At this time, we are proposing not to apply the same electronic reporting for certification and QA test data from HCl or PM CEMS but are instead relying on the existing provisions in Parts 60 and 63.

Our rationale for this is as follows. We considered two possible Hg monitoring and reporting options to demonstrate continuous compliance. The first option would be for Hg CEMS and sorbent trap systems to be certified and quality-assured according to PS 12A and 12B in Appendix B to 40 CFR part 60. Procedure 5 in Appendix F to Part 60 would be followed for on-going QA. Semiannual hard copy reporting of "deviations" would be required, along with data assessment reports (DARs). Even though this option would not require electronic reporting of either hourly Hg emissions data or QA test results, it still would require affected sources to have a data handling system (DAHS) that: (1) Is programmed to capture data from the Hg CEMS; (2) uses the criteria in Appendix F to Part 60 to validate or invalidate the Hg data; (3) calculates hourly averages for Hg concentration and for the auxiliary parameters (*e.g.,* flow rate, O_2 or CO_2 concentration) that are needed to convert Hg concentrations to the units of the emission standard; (4) calculates 30 boiler operating day rolling average Hg emission rates; and (5) identifies any deviations that must be reported to the Agency.

The second option would simply integrate Hg emissions data and QA test results into the existing Part 75-compliant DAHS that is installed at the vast majority of the coal-fired EGUs. We obtained feedback from several DAHS vendors indicating that the cost of modifying the existing Part 75 DAHS systems to accommodate hourly reporting of Hg CEMS and sorbent trap data would be similar, and in some cases, less than the cost of the first option. Also, there would be little or no cost to industry for the flow rate, CO_2, or O_2, and moisture monitors needed to convert Hg concentration to the units of the standard, because, as previously noted, almost all of the EGUs already have these monitors in place. In view of these considerations, we have decided in favor of this second option for Hg.

Requiring the reporting of hourly Hg emissions data from EGUs would be advantageous, both to EPA and industry. The DAHS could be automated to demonstrate compliance with the standard on a continuous basis. The data could then be submitted to the Agency electronically, thereby eliminating the need for the Agency to request additional information for compliance determinations and program implementation.

Today's proposed rule would also require quarterly electronic reporting of hourly SO_2 CEMS data, PM CEMS data, and HCl CEMS data (for sources electing to demonstrate continuous compliance using certified CEMS), as well as electronic summaries of emission test results (for sources demonstrating continuous compliance by periodic stack testing), and semiannual electronic "deviation" reports (for sources that monitor parameters or assess compliance in other ways). As discussed in detail in the paragraphs below, requiring electronic reporting in lieu of traditional hard copy reports would enable utility sources to demonstrate continuous compliance with the applicable emissions limitations of this proposed rule, using a process that is familiar to them and consistent with the procedures that they currently follow to comply with ARP and other mass-based emissions trading programs.

Currently, utility sources that are subject to the ARP and other EPA emissions trading programs use the Emissions Collection and Monitoring Plan System (ECMPS) to process and evaluate continuous monitoring data and other information in an electronic format for submittal to the Agency. In addition to receiving hourly emissions data, this system supports the maintenance of an electronic "monitoring plan" and is designed to receive the results of monitoring system certification test data and ongoing QA test data. Emissions data are submitted quarterly through ECMPS, and users are given feedback on the quality of their reports before the data are submitted. This allows them to make corrections or otherwise address issues with the reports prior to making their official submittals. Despite the stringency and thoroughness of the data validation checks performed by the ECMPS software, the implementation of this process has resulted in very few errant reports being submitted each quarter. This has saved both industry and the Agency countless hours of valuable time, which in years past, was spent troubleshooting errors in the quarterly reports. EPA is proposing to apply the same basic quarterly data collection process to Hg, HCl, and PM CEMS data, and to modify ECMPS to be able to accommodate summarized stack test data and semiannual deviation reports.

The ECMPS process divides electronic data into three categories, the first of which is monitoring plan data. The electronic monitoring plan is maintained as a separate entity, and can be updated at any time, if necessary. The monitoring plan documents the characteristics of the affected units (*e.g.,* unit type, rated heat input capacity, *etc.*) and the monitoring methodology that is used for each parameter (*e.g.,* CEMS). The monitoring plan also describes the type of monitoring equipment used (hardware and software components), includes analyzer span and range settings, and provides other useful information. Nearly all coal-fired EGUs are subject to the ARP and have established electronic monitoring plans that describe their required SO_2, flow rate, CO_2 or O_2, and, in some cases, moisture monitoring systems. The ECMPS monitoring plan format could easily accommodate this same type of information for Hg, HCl, and PM CEMS, with the addition of a few codes for the new parameters.

The second type of data collected through ECMPS is certification and QA test data. This includes data from linearity checks, relative accuracy test audits (RATAs), cycle time tests, 7-day calibration error tests, and a number of other QA tests that are required to validate the emissions data. The results of these tests can be submitted to EPA as soon as the results are received, with one notable exception. Daily calibration error tests are not treated as individual QA tests, due to the large number of records generated each quarter. Rather, these tests are included in the quarterly electronic reports, along with the hourly emissions data.

The ECMPS system is already set up to receive and process certification and QA data from SO_2, CO_2, O_2, flow rate, and moisture monitoring systems that are installed, certified, maintained, operated, and quality-assured according to Part 75. EGUs routinely submit these data to EPA under the ARP and other emissions trading programs.

To accommodate the certification and QA tests for Hg CEMS and sorbent trap monitoring systems, relatively few changes would have to be made to the structure and functionality of ECMPS, because most of the tests are the same ones that are required for other gas monitors. More substantive changes to the system would be required to receive and process the certification and QA tests required for HCl and PM CEMS, and to receive summarized stack test results, and the types of data provided in semiannual compliance reports; however, we believe these changes are implementable. Another modification that could be made to ECMPS would be to disable the Part 75 bias test (which is required for certain types of monitors under EPA's emissions trading programs) for Hg, HCl, and PM CEMS, if bias adjustment of the data from these monitors is believed to be unnecessary or inappropriate for compliance with the proposed rule. We are proposing to make this modification and solicit comment on it.

The third type of data collected through ECMPS is the emissions data, which, as previously noted, is reported on a quarterly schedule. The reports must be submitted within 30 days after the end of each calendar quarter. The emissions data format requires hourly reporting of all measured and calculated emissions values, in a standardized electronic format. Direct measurements made with CEMS, such as gas concentrations, are reported in a Monitor Hourly Value (MHV) record. A typical MHV record for gas concentration includes data fields for: (1) The parameter monitored (*e.g.,* SO_2); (2) the unadjusted and bias-adjusted hourly concentration values (note that if bias adjustment is not required, only the unadjusted hourly value is reported); (3) the source of the data, *i.e.,* a code indicating either that each reported hourly concentration is a quality-assured value from a primary or backup monitor, or that quality-assured data were not obtained for the hour; and (4) the percent monitor availability (PMA), which is updated hour-by-hour. This generic record structure could easily accommodate hourly average measurements from Hg, HCl, and PM CEMS.

The ECMPS reporting structure is quite flexible, which makes it useful for assessing compliance with various emission limits. The Derived Hourly Value (DHV) record provides the means whereby a wide variety of quantities that can be calculated from the hourly emissions data can be reported. For instance, if an emission limit is expressed in units of lb/MMBtu, the

DHV record can be used to report hourly pollutant concentration values in these units of measure, since the lb/MMBtu values can be derived from the hourly pollutant and diluent gas (CO_2 or O_2) concentrations reported in the MHV records. ECMPS can also accommodate multiple DHV records for a given hour in which more than one derived value is required to be reported. Therefore, if hourly Hg, HCl, and PM concentration data are reported through ECMPS, the DHV record, in conjunction with the appropriate equations and auxiliary information such as heat input and electrical load (all of which are reported hourly in the emissions reports), could be used to report hourly data in the units of the emission standards (*e.g.,* lb/MMBtu, lb/TBtu, lb/GWh, *etc.*).

The ARP and other emissions trading programs that report emissions data to EPA using Part 75 are required to provide a complete data record. Emissions data are required to be reported for every unit operating hour. When CEMS are out of service, substitute data must be reported to fill in the gaps. However, for the purposes of compliance with a NESHAP, reporting substitute data during monitor outages may not be appropriate. Today's proposed rule would not require the use of missing data substitution for Hg monitoring systems. We intend to extend this concept to HCl and PM CEMS, if we receive data from those types of monitors. Hours when a monitoring system is out of service would simply be counted as hours of monitor down time, to be counted against the percent monitor availability. We solicit comment on this proposed approach.

As previously stated, EPA is proposing to add Hg monitoring provisions as Appendix A to 40 CFR part 63, subpart UUUUU, and to require these provisions to be used to document continuous compliance with the proposed rule, for units that cannot qualify as LEEs. Proposed Appendix A would consolidate all of the Hg monitoring provisions in one place. Today's proposed rule would provide two basic Hg continuous monitoring options: Hg CEMS and sorbent trap monitoring systems.

Proposed Appendix A would require the Hg CEMS and sorbent trap monitoring systems to be initially certified and then to undergo periodic QA testing. The certification tests required for the Hg CEMS would be a 7-day calibration error test, a linearity check, using NIST-traceable elemental Hg standards, a 3-level system integrity check (similar to a linearity check), using NIST-traceable oxidized Hg standards, a cycle time test, and a RATA. A bias test would not be required. The performance specifications for the required certification tests, which are summarized in Table A–1 of proposed Appendix A, would be the same as those that were published in support of CAMR. For ongoing QA of the Hg CEMS, proposed Appendix A would require daily calibrations, weekly single-point system integrity checks, quarterly linearity checks (or 3-level system integrity checks) and annual RATAs. These QA test requirements and the applicable performance criteria, which, once again, are the same as the ones we had published in support of CAMR, are summarized in Table A–3 in proposed Appendix A. For sorbent trap monitoring systems, a RATA would be required for initial certification, and annual RATAs would be required for ongoing QA. The performance specification for these RATAs would be the same as for the RATAs of the Hg CEMS. Bias adjustment of the measured Hg concentration data would not be required. However, for routine, day-to-day operation of the sorbent trap system, proposed Appendix A provides the owner or operator the option to follow the procedures and QA/QC criteria in PS 12B in Appendix B to 40 CFR part 60. Performance Specification 12B is nearly identical to the vacated Appendix K to Part 75. The Part 75 concepts of: (1) Determining the due dates for certain QA tests on the basis of "QA operating quarters"; and (2) grace periods for certain QA tests, would apply to both Hg CEMS and sorbent trap monitoring systems.

Mercury concentrations measured by Hg CEMS or sorbent trap systems would be used together with hourly flow rate, diluent gas, moisture, and electrical load data, to express the Hg emissions in units of the proposed rule, on an hourly basis (*i.e.,* lb/TBtu or lb/GWh). Proposed section 6 of Appendix A provides the necessary equations for these unit conversions. These hourly values could then be "rolled up" within the DAHS into the proper 30 boiler operating day averaging period, to assess compliance. A report function could be added to ECMPS to show the results of these calculations, and to highlight any values in excess of the standard.

The proposed rule would specify record keeping and reporting requirements for the two Hg monitoring methodologies. Essential information pertaining to each methodology would be represented in the electronic monitoring plan. Hourly Hg concentration data would be reported in all cases. However, for the sorbent trap option, a single Hg concentration value would be reported for extended periods of time, since a sorbent trap monitoring system does not provide hour-by-hour measurements of Hg concentration. The results of all required certification and QA tests would also be reported. Missing data substitution for Hg concentration would not be required for hours in which quality-assured data are not obtained. Special codes would be reported to identify these hours.

Of all the types of NESHAP compliance data that could be brought into ECMPS (*i.e.,* CEMS data, stack test summaries, and semiannual compliance reports), the easiest to implement would be the Hg monitoring data, because, as noted above, we had published specific Hg monitoring and reporting provisions in Part 75 prior to the vacatur of CAMR, and had made considerable progress in modifying ECMPS to receive these data. Today's proposed rule provides detailed regulatory language in proposed Appendix A to 40 CFR part 63, subpart UUUUU, pertaining to the monitoring of Hg emissions and reporting the data electronically.

We are requesting comment on these proposed compliance approaches and on whether our proposed "one stop shopping" approach to reporting MACT compliance information electronically is desirable. In your comments, we ask you to consider the merits of requiring reporting of results from PM CEMS and HCl CEMS to ECMPS and consequent development of a monitoring and reporting scheme for these CEMS that is compatible with ECMPS. If you favor our proposed streamlined continuous compliance approach, we request input on how to make the reporting process user-friendly and efficient. EPA believes that if the essential data that are reported under the Agency's emissions trading programs and the proposed rule are all sent to the same place, this could significantly reduce the burden on industry and bring about national consistency in assessing compliance.

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

All new and existing sources would be required to comply with certain requirements of the General Provisions (40 CFR part 63, subpart A), which are identified in Table 10 of this proposed rule. The General Provisions include specific requirements for notifications, recordkeeping, and reporting.

Each owner or operator would be required to submit a notification of compliance status report, as required by § 63.9(h) of the General Provisions. This proposed rule would require the owner or operator to include in the notification of compliance status report certifications of compliance with rule requirements.

Except for units that use CEMS for continuous compliance, semiannual compliance reports, as required by § 63.10(e)(3) of subpart A, would be required for semiannual reporting periods, indicating whether or not a deviation from any of the requirements in the rule occurred, and whether or not any process changes occurred and compliance certifications were reevaluated. As previously discussed, we are proposing to use the ECMPS system to receive the essential information contained in these semiannual compliance reports electronically. For units using CEMS, quarterly electronic reporting of hourly Hg and associated (O_2, CO_2, flow rate, and/or moisture) monitoring data, as well as electronic reporting of monitoring plan data and certification and QA test results, would be required, also through ECMPS.

This proposed rule would require records to demonstrate compliance with each emission limit and work practice standard. These recordkeeping requirements are specified directly in the General Provisions to 40 CFR part 63, and are identified in Table 9 of this proposed rule.

Records of continuously monitored parameter data for a control device if a device is used to control the emissions or CEMS data would be required.

We are proposing that you must keep the following records:

(1) All reports and notifications submitted to comply with this proposed rule.

(2) Continuous monitoring data as required in this proposed rule.

(3) Each instance in which you did not meet each emission limit and each operating limit (*i.e.,* deviations from this proposed rule).

(4) Daily hours of operation by each source.

(5) Total fuel use by each affected liquid oil-fired source electing to comply with an emission limit based on fuel analysis for each 30 boiler operating day period along with a description of the fuel, the total fuel usage amounts and units of measure, and information on the supplier and original source of the fuel.

(6) Calculations and supporting information of chlorine fuel input, as required in this proposed rule, for each affected liquid oil-fired source with an applicable HCl emission limit.

(7) Calculations and supporting information of Hg and HAP metal fuel input, as required in this proposed rule, for each affected source with an applicable Hg and HAP metal (or PM) emission limit.

(8) A signed statement, as required in this proposed rule, indicating that you burned no new fuel type and no new fuel mixture or that the recalculation of chlorine input demonstrated that the new fuel or new mixture still meets chlorine fuel input levels, for each affected source with an applicable HCl emission limit.

(9) A signed statement, as required in this proposed rule, indicating that you burned no new fuels and no new fuel mixture or that the recalculation of Hg and/or HAP metal fuel input demonstrated that the new fuel or new fuel mixture still meets the Hg and/or HAP metal fuel input levels, for each affected source with an applicable Hg and/or HAP metal emission limit.

(10) A copy of the results of all performance tests, fuel analyses, performance evaluations, or other compliance demonstrations conducted to demonstrate initial or continuous compliance with this proposed rule.

(11) A copy of your site-specific monitoring plan developed for this proposed rule as specified in 63 CFR 63.8(e), if applicable.

We are also proposing to require that you submit the following additional notifications:

(1) Notifications required by the General Provisions.

(2) Initial Notification no later than 120 calendar days after you become subject to this subpart.

(3) Notification of Intent to conduct performance tests and/or compliance demonstration at least 60 calendar days before the performance test and/or compliance demonstration is scheduled.

(4) Notification of Compliance Status 60 calendar days following completion of the performance test and/or compliance demonstration.

L. Submission of Emissions Test Results to EPA

EPA must have performance test data to conduct effective reviews of CAA sections 112 and 129 standards, as well as for many other purposes including compliance determinations, emission factor development, and annual emission rate determinations. In conducting these required reviews, EPA has found it ineffective and time consuming, not only for us, but also for regulatory agencies and source owners and operators, to locate, collect, and submit performance test data because of varied locations for data storage and varied data storage methods. In recent years, though, stack testing firms have typically collected performance test data in electronic format, making it possible to move to an electronic data submittal system that would increase the ease and efficiency of data submittal and improve data accessibility.

Through this proposal, EPA is presenting a step to increase the ease and efficiency of data submittal and improve data accessibility. Specifically, EPA is proposing that owners and operators of EGUs submit electronic copies of required performance test reports to EPA's WebFIRE database. The WebFIRE database was constructed to store performance test data for use in developing emission factors. A description of the WebFIRE database is available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.*

As proposed above, data entry would be through an electronic emissions test report structure called the Electronic Reporting Tool (ERT). The ERT would be able to transmit the electronic report through EPA's Central Data Exchange (CDX) network for storage in the WebFIRE database making submittal of data very straightforward and easy. A description of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/ert_tool.html.*

The proposal to submit performance test data electronically to EPA would apply only to those performance tests conducted using test methods that will be supported by the ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at *http://www.epa.gov/ttn/chief/ert/ert_tool.html.* We believe that industry would benefit from this proposed approach to electronic data submittal. Having these data, EPA would be able to develop improved emission factors, make fewer information requests, and promulgate better regulations.

One major advantage of the proposed submittal of performance test data through the ERT is a standardized method to compile and store much of the documentation required to be reported by this rule. Another advantage is that the ERT clearly states what testing information would be required. Another important proposed benefit of submitting these data to EPA at the time the source test is conducted is that it should substantially reduce the effort involved in data collection activities in the future. When EPA has performance test data in hand, there will likely be fewer or less substantial data collection requests in conjunction with prospective required residual risk assessments or technology reviews. This would result in a reduced burden on both affected facilities (in terms of reduced manpower to respond to data collection requests) and EPA (in terms of preparing and distributing data collection requests and assessing the results).

State, local, and tribal agencies could also benefit from more streamlined and accurate review of electronic data submitted to them. The ERT would allow for an electronic review process rather than a manual data assessment making review and evaluation of the source provided data and calculations easier and more efficient. Finally, another benefit of the proposed data submittal to WebFIRE electronically is that these data would greatly improve the overall quality of existing and new emissions factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, EPA would be able to ensure that emission factors, when updated, represent the most current range of operational practices. In summary, in addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with performance test data would save industry, state, local, tribal agencies, and EPA significant time, money, and effort while also improving the quality of emission inventories and, as a result, air quality regulations. In this action, as previously stated, EPA is proposing a step to improve data accessibility. Specifically, we are proposing that you submit, to an EPA database, electronic copies of reports of certain performance tests required under the proposed rule through our ERT; however, we request comment on the feasibility of using a modified version of ECMPS, which the utility industry already is familiar with and uses for reporting under the Title IV ARP and other emissions trading programs, to provide this information.

ECPMS could be modified to allow electronic submission of periodic data, including, but not limited to, 30 day averages of parametric data, 30 day average fuel content data, stack test results, and performance of tune up records. These data will need to be submitted and reviewed, and we believe electronic submission via a specific format already in use for other submissions eases understanding, affords transparency, ensures consistency, and saves time and money.

We seek comment on alternatives to the use of a modified ECMPS for electronic data submission. Commenters should describe alternate means for supplying these data and information on associated reliability, the cost, the ease of implementation, and the transparency to the public of the information.

V. Rationale for This Proposed NESHAP

A. How did EPA determine which subcategories and sources would be regulated under this proposed NESHAP?

As stated above, EPA added coal- and oil-fired EGUs to the CAA section 112(c) list on December 20, 2000. This proposed rule proposes standards for the subcategories of coal- and oil-fired EGUs as defined in this preamble. Sources in these subcategories may potentially include combustion units that are at times IB units or solid waste incineration units subject to other standards under CAA section 112 or to standards under CAA section 129. We request comment on whether the proposed rule should address how sources that change fuel input (*e.g.,* burn solid waste or biomass), or otherwise take action that would change the source's applicability (*e.g.,* stop or start selling electricity to the utility power distribution system), must demonstrate continuous compliance with all applicable standards. Note that units subject to another CAA section 112 standard or to solid waste incineration unit standards established under CAA section 129 are not subject to this proposed rule during the period of time they are subject to the other CAA section 112 or 129 standards.

The scope of the EGU source category is limited to coal- and oil-fired units meeting the CAA section 112(a)(8) definition and the proposed definition of "fossil fuel fired" discussed above.

Under CAA section 112(d)(1), the Administrator has the discretion to "* * * distinguish among classes, types, and sizes of sources within a category or subcategory in establishing * * *" standards. For example, differences between given types of units can lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques. In the December 2000 listing, EPA initially established and listed two subcategories of fossil fuel-fired EGUs: Coal-fired and oil-fired. The design, operating, and emissions information that EPA has reviewed indicates that there are significant design and operational differences in unit design that distinguish different types of EGUs within these two subcategories, and, because of these differences, we have proposed to establish two subcategories for coal-fired EGUs, two subcategories for oil-fired EGUs, and an IGCC subcategory for gasified coal and solid oil-derived fuel (*e.g.,* petroleum coke), as stated above and discussed further below.

EGU systems are designed for specific fuel types and will encounter problems if a fuel with characteristics other than those originally specified is fired. Changes to the fuel type would generally require extensive changes to the fuel handling and feeding system (*e.g.,* liquid oil-fired EGUs cannot fire solid fuel without extensive modification). Additionally, the burners and combustion chamber would need to be redesigned and modified to handle different fuel types and account for increases or decreases in the fuel volume. In some cases, the changes may reduce the capacity and efficiency of the EGU. An additional effect of these changes would be extensive retrofitting needed to operate using a different fuel. These effects must be considered whether one is discussing two fuel types (*e.g.,* coal vs. oil) or two ranks or forms of fuel within a given fuel type (*e.g.,* gasified vs. solid coal or solid oil-derived fuel).

The design of the EGU, which is dependent in part on the type of fuel being burned, impacts the degree of combustion, and may impact the level and kind of HAP emissions. EGUs emit a number of different types of HAP emissions. Organic HAP are formed from incomplete combustion and are primarily influenced by the design and operation of the unit. The degree of combustion may be greatly influenced by three general factors: Time, turbulence, and temperature. On the other hand, the amount of fuel-borne HAP (non-Hg metals, Hg, and acid gases) is primarily dependent upon the composition of the fuel. These fuel-borne HAP emissions generally can be controlled by either changing the fuel property before combustion or by removing the HAP from the flue gas after combustion.

We first examined the HAP emissions results to determine if subcategorization by unit design type was warranted. Normally, any basis for subcategorizing (*e.g.,* type of unit) must be related to an effect on emissions, rather than some difference which does not affect emissions performance. We concluded that the data were sufficient for one or more HAP for determining that a distinguishable difference in performance exists based on the following five unit design types: coal-fired units designed to burn coal with greater than or equal to 8,300 Btu/lb (for Hg emissions only); coal-fired units designed to burn coal with less than 8,300 Btu/lb (for Hg emissions only); IGCC units; liquid oil units; and solid oil-derived units. For other types of units noted above (*e.g.,* FBC, stoker, wall-fired, tangential (T)-fired), there was no significant difference in emissions that would justify subcategorization. Because in the five cases different types of units have different emission characteristics for one or more HAP, we have determined that these types of units should be subcategorized. Accordingly, we propose to subcategorize EGUs based on the five unit types.

For Hg emissions from coal-fired units, we have determined that different emission limits for the two subcategories are warranted. There were no EGUs designed to burn a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12 percent of sources for Hg emissions, indicating a difference in the emissions for this HAP from these types of units. The boiler of a coal-fired EGU designed to burn coal with that heat value is bigger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories. For all other HAP from these two subcategories of coal-fired units, the data did not show any difference in the level of the HAP emissions and, therefore, we have determined that it is not reasonable to establish separate emissions limits for the other HAP.

For all HAP emissions from oil-fired units, we have determined that two subcategories are warranted. EGUs designed to burn a solid fuel (*e.g.,* petroleum coke) derived from the refining of petroleum (oil) are of a different design, and have different emissions, than those designed to burn liquid oil. In addition, EGUs designed to burn liquid oil cannot, in fact, accommodate the solid fuel derived from the refining of oil. Thus, we are proposing to subcategorize oil-fired EGUs into two subcategories based on the type of units designed to burn oil in its different physical states.

EGUs employing IGCC technology combust a synthetic gas derived from solid coal or solid oil-derived fuel. No solid fuel is directly combusted in the unit during operation (although a coal- or solid oil-derived fuel is fired), and both the process and the emissions from IGCC units are different from units that combust solid coal or petroleum coke. Thus, we are proposing to subcategorize IGCC units as a distinct type of EGU for this proposed rule. EPA solicits comment on these subcategorization approaches.

Additional subcategories have been evaluated, including those suggested by the SERs serving on the SBAR established under the SBREFA. These suggestions include subcategorization of lignite coal vs. other coal ranks; subcategorization of Fort Union lignite coal vs. Gulf Coast lignite coal vs. other coal ranks; subcategorization by EGU size (*i.e.,* MWe); subcategorization of base load vs. peaking units (*e.g.,* low capacity utilization units); subcategorization of wall-fired vs. T-fired units; and subcategorization of small, non-profit-owned units vs. other units.

EPA has reviewed the available data and does not believe that these suggested approaches merit subcategorization. For example, there are both large and small units among the EGUs comprising the top performing 12 percent of sources and small entities may own minor portions of large EGUs and/or individual EGUs themselves. In addition, because the proposed format of the standards is lb/MMBtu (or TBtu for Hg), the size should only affect the rate at which a unit generates electricity and, with a lower electricity generation rate, there is less fuel consumption and, therefore, less emissions of fuel-borne HAP (i.e., acid gas and metal HAP). Further, with the exception of IGCC and as noted elsewhere regarding boiler height-to-depth ratio, there is no indication that EGU type (*e.g.,* wall-fired, T-fired, FBC, stoker-fired), has any impact on HAP emission levels as all of these types are within the top performing 12 percent of sources. There is also little indication that operating load has any significant impact on HAP emissions or on the type of control demonstrated on the unit.

EPA solicits comment on whether we should further subcategorize the source category. In commenting, commenters should provide a definition or threshold that would distinguish the proposed subcategory from the remainder of the EGU population and, to support this distinction, an estimate of how many EGUs would be impacted by the subcategorization approach, the amount of time such impacted units operate, the extent to which such impacted units would move out of and back into the subcategory in a given year (or other period of time), and any other information the commenter believes is pertinent. For example, if a commenter were to suggest subcategorizing low capacity factor or peaking units from the remainder of the EGU population, in addition to the suggested threshold capacity factor, information on the number of such units that would be impacted, the amount of time such units are running (capacity utilization), the extent to which such units are low capacity factor units in a given year vs. operating at a higher capacity factor, and data from the units when operating both as peaking units and as baseload units (among other information) would need to be provided to support the comment. Commenters should further explain how their suggested subcategorizations constitute a "size," "type," or "class," as those terms are used in CAA section 112(d)(1).

B. How did EPA select the format for this proposed rule?

This proposed rule includes numerical emission limitations for PM, Hg, and HCl (as well as for other alternate constituents or groups). Numerical emission limitations provide flexibility for the regulated community, because they allow a regulated source to choose any control technology, approach, or technique to meet the emission limitations, rather than requiring each unit to use a prescribed control method that may not be appropriate in each case.

We are proposing numerical emission rate limitations as a mass of pollutant emitted per heat energy input to the EGU for the fuel-borne HAP for existing sources. The most typical units for the limitations are lb/MMBtu of heat input (or, in the case of Hg, lb/TBtu). The mass per heat input units are consistent with other Federal and many state EGU regulations and allows easy comparison between such requirements. Additionally, this proposed rule contains an option to monitor inlet chlorine, fluorine, non-Hg metal, and Hg content in the liquid oil to meet outlet emission rate limitations. This is reasonable because oil-fired units may choose to remove these fuel-borne HAP from the oil before combustion in lieu of installing air pollution control devices. This option can only be done on a mass basis by liquid oil-fired EGUs. We request comment on the viability of this approach for IGCC units.

We are proposing numerical emission rate limitations as a mass of pollutant emitted per megawatt- or gigawatt-hour (MWh or GWh) gross output from the EGU for the fuel-borne HAP for new sources and as an alternate format for existing sources. An outlet numerical emission limit is also consistent with the format of other regulations (*e.g.,* the EGU NSPS, 40 CFR part 60, subpart Da).

EGUs can emit a wide variety of compounds, depending on the fuel burned. Because of the large number of HAP potentially present and the disparity in the quantity and quality of the emissions information available, EPA grouped the HAP into five categories based on available information about the pollutants and on experiences gained on other NESHAP: Hg, non-Hg metallic HAP, inorganic (i.e., acid gas) HAP, non-dioxin/furan organic HAP, and dioxin/furan organic HAP. The pollutants within each group have similar characteristics and can be controlled with the same techniques. For example, non-Hg metallic HAP can be controlled with PM controls. We chose to look at Hg separately from other metallic HAP due to its different chemical characteristics and its different control technology feasibility.

Next, EPA identified compounds that could be used as surrogates for all the compounds in each pollutant category. Existing technologies that have been installed to control emissions of other (*e.g.,* criteria) pollutants are expected to provide coincidental or "co-benefit" control of some of the HAP. For example, technologies for PM control (*e.g.,* ESP, FF) can effectively remove Hg that is bound to particulate such as injected sorbents, unburned carbon, or other fly ash particles. Similarly, PM control technologies are effective at reducing emissions of the non-Hg metal HAP that are present in the fly ash as solid particulate. Flue gas desulfurization technologies typically remove SO_2 using acid-base neutralization reactions (usually via contact with alkaline solids or slurries). This approach is also effective for other acid gases as well, including the acid gas HAP (HCl, HF, Cl_2, and HCN).

EGUs routinely measure operating parameters (flow rates, temperatures, pH, pressure drop, etc.) and flue gas composition for process control and monitoring and for emission compliance and verification. Some of these routinely or more easily-measured parameters or components may serve as surrogates or indicators of the level of control of one or more of the HAP that may not be easily or routinely measured or monitored. The use of more easily-measured components or process conditions as surrogates or predictors of HAP emissions can greatly simplify monitoring requirements under this proposed rule and, in some cases, provide more reliable results.

In order to evaluate potential surrogacy relationships, the EPA Office of Research and Development (ORD), in collaboration with OAR, conducted a series of tests in the Agency's Multipollutant Control Research Facility (MPCRF), a pilot-scale combustion and control technology research facility located at EPA's Research Triangle Park campus in North Carolina. The combustor is rated at 4 MMBtu/hr (approximately 1.2 megawatt-thermal (MW_t)). It is capable of firing all ranks of pulverized coal, natural gas, and fuel oil. The facility is equipped with low NO_X burners and an SCR unit for NO_X control. The system can be configured to allow the flue gas to flow through either an ESP or a FF for PM control. The facility also uses a wet lime-based FGD scrubber for control of SO_2 emissions. The system is well equipped with CEMS for on-line measurement of O_2, CO_2, NO_X (nitrogen oxide, NO, and nitrogen dioxide, NO_2), SO_2, CO, Hg, and THC. There are multiple sampling ports throughout the flue gas flow path. The facility is designed for ease of modification so that various control technologies and configurations can be tested. The facility has a series of heat exchangers to remove heat such that the flow path of the flue gas has a similar time-temperature profile to that seen in a typical full-scale coal-fired EGU.

Eleven independent tests were performed in the MPCRF in order to examine potential surrogacy relationships. Three types of coal (eastern bituminous, subbituminous, and Gulf Coast lignite) were tested. The PM control was also varied; in some tests, the ESP was used whereas the FF was used in others. Three potential surrogacy relationships were examined during the testing program. The potential for use of PM control as a surrogate for the control of the non-Hg metal HAP (Be, As, Cd, Co, Cr, Mn, Ni, Pb, Sb, and Se) was examined. The potential for use of HCl or SO_2 control as a surrogate for other acid gases (HCl, HF, Cl_2) was studied. In addition, several potential surrogate relationships were examined for the non-dioxin/furan organic HAP. No surrogate studies were conducted for Hg; we have not identified any surrogates for Hg and, thus, are regulating Hg directly. No surrogacy studies were conducted for dioxin/furan organic HAP because we believed the S:Cl ratio in the flue gas would be greater than 1.0, meaning that the formation of dioxins/furans would be inhibited. Moreover, it was anticipated that levels of these compounds would be very low, and, as mentioned earlier in the preamble, the approved 2010 ICR sampling methods for dioxin/furan organic HAP required 8-hour sampling periods; such a long sampling period was not practical in our pilot system and would not be practical on a continuous basis.

The results of the program indicated that the control of all non-Hg metal HAP (except Se) was consistently similar to the control of the bulk total PM (PM_{total}). The average PM_{total} control during the tests was 99.5 percent. All of the non-Hg metal HAP were controlled along with the PM_{total} at levels greater than 95 percent for measurements taken for particulate control using both the ESP and the FF. Average control for the test series for each of the metals was (for all coals and all configurations): Sb—95.3 percent; As—98.0 percent; Be—98.5 percent; Cd—98.7 percent; Cr—98.0 percent; Co—99.3 percent; Pb—99.2 percent; Mn—99.5 percent; and Ni—97.6 percent.

The results for Se control were less consistent. When subbituminous coal was fired, the control of Se was consistently very good (average 98.9 percent), regardless of the PM control device being used. When using the FF as the primary PM control device, the Se control was consistently very good (average 99.2 percent) regardless of the coal being fired. Control of Se when the ESP was the primary PM control device was variable. When subbituminous coal was fired, the control of Se through the ESP was greater than 99 percent. When lignite was fired, the control through the ESP was about 80 percent. However, when the eastern bituminous coal was fired, the Se control through the ESP ranged from zero to 73 percent.

The variability in the performance of Se control with coal rank and PM control device can be explained by the known behavior and chemistry of Se in the combustion and flue gas environments. Selenium is a metalloid that sits just below sulfur on the periodic table and is, chemically, very similar to sulfur. In the high temperature combustion environment, Se is likely to be present as gas phase SeO_2 (as, similarly, sulfur is likely to be present as gaseous SO_2). Much like SO_2, SeO_2 is a weak acid gas. The testing in the pilot-scale combustion facility showed that Se in the flue gas entering the PM control device tended to be predominantly in the gas phase (55 to 90 percent) when firing eastern bituminous coal and predominantly in the solid phase when firing subbituminous coal (greater than 95 percent) and Gulf Coast lignite (80 percent). This is explained by the large difference in calcium (Ca) content of those fuels. The ash from the bituminous coal contained 1.4 weight percent Ca, whereas the ashes from the subbituminous coal and Gulf Coast lignite contained Ca at 10.0 weight percent and 9.0 weight percent, respectively. The alkaline Ca in the fly ash effectively neutralized the SeO_2 acid gas, forming a particulate that is easily removed in the PM control device. The bituminous fuel contained insufficient free Ca to completely neutralize the SeO_2 and the much increased levels of SO_2 in that flue gas. The good performance through the FF (regardless of the fuel being fired) can be attributed to the increased contact between the gas stream and the filter cake on the FF. This allows more of the SeO_2 to adsorb or condense on fly ash particles—either alkaline particles or unburned carbon. Because SeO_2 behaves very similarly to its sulfur analog, SO_2, it can be expected to also be removed effectively in standard FGD technologies (wet scrubbers, dry scrubbers, DSI, etc.). Therefore, Se will either fall in to the category of "non-Hg metal HAP" and be effectively removed in a PM control device, or it will fall into the category of "acid gas HAP" as gaseous SeO_2 and be effectively removed using FGD technologies.

Two of the 11 tests were specifically designated for testing of surrogacy relationships relating to the acid gas HAP. Eastern bituminous coal was fired and duct samples were taken upstream and downstream of the lime-based wet FGD scrubber. Those tests showed, as expected, very high levels of control for HCl (greater than 99.9 percent control). The control of HF was greater than 92 percent for the first run and greater than 76 percent for the second run. The control of Cl_2 was greater than 76 percent for the first run and greater than 92 percent for the second run. (Note that both of these control efficiencies were likely much higher than the reported values because the outlet measurements were below the MDL for both HF and Cl_2. The control efficiencies were calculated using the MDL value.) The control efficiency for SO_2 for the runs was greater than 98 percent.

Tests were also conducted to examine potential surrogacy relationships for the non-dioxin/furan organic HAP. The amounts of Hg, non-Hg metals, HCl, HF, and Cl_2 in the flue gas are directly related to the amounts of Hg, non-Hg metals, chlorine, and fluorine in the coal. Control of these components generally requires downstream control technology. However, the presence of the organics in the flue gas is not related to the composition of the fuel but rather they are a result of incomplete or poor combustion. Control of the organics is often achieved by improving combustion conditions to minimize formation or to maximize destruction of the organics in the combustion environment.

During the pilot-scale tests, sampling was conducted for semi-volatile and volatile organic HAP and aldehydes. On-line monitors also collected data on THC, CO, O_2, and other processing conditions. Total hydrocarbons and CO have been used previously as surrogates for the presence of non-dioxin/furan organics. Carbon monoxide has often been used as an indicator of combustion conditions. Under conditions of ideal combustion, a carbon-based or hydrocarbon fuel will completely oxidize to produce only CO_2 and water. Under conditions of incomplete or non-ideal combustion, a greater amount of CO will be formed.

With complex carbon-based fuels, combustion is rarely ideal and some CO and concomitant organic compounds are expected to be formed. Because CO and organics are both products of poor combustion, it is logical to expect that limiting the concentration of CO would also limit the production of organics. However, it is very difficult to develop direct correlations between the average concentration of CO and the amount of organics produced during the prescribed sampling period in the MPCRF (which was 4 hours for the pilot-scale tests described here). This is especially true for low values of CO as one would expect corresponding low quantities of organics to be produced. Samples of coal combustion flue gas have mostly shown very low quantities of the organic compounds of interest. Some of the flue gas organics may also be destroyed in the high temperature post combustion zone (whereas the CO would remain stable). Semi-volatile organics may also condense on PM and be removed in the PM control device.

The average CO from the pilot-scale tests ranged from 23 to 137 ppm for the bituminous coals tests, from 43 to 48 ppm for the subbituminous coal tests and from 93 to 129 ppm for the Gulf Coast lignite tests. However, it was difficult to correlate that concentration to the quantity of organics produced for several reasons. The most difficult problems are associated with the large number of potential organics that can be produced (both those on the HAP list and those that are not on the HAP list). This is further complicated by the organic compounds tending to be at or below the MDL in coal combustion flue gas samples. Further, there are complications associated with the CO concentration values. Some of the runs with very similar average concentrations of CO had very different maximum concentrations of CO (*i.e.,* some of the runs had much more stable emissions of CO whereas others had some excursions, or "spikes," in CO concentration). For example, one of the bituminous runs had an average CO concentration of 69 ppm but a maximum concentration of 1,260 ppm (due to a single "spike" of CO during a short upset). Comparatively, another bituminous run had a higher average CO concentration at 137 ppm but a much lower maximum CO value at 360 ppm.

In the pilot tests, the THC measurement was inadequate as the detection limit of the instrument was much too high to detect changes in the very low concentrations of hydrocarbons in the flue gas.

Based on the testing described above and the emissions data received under the 2010 ICR, we are proposing surrogate standards for the non-Hg metallic HAP and the non-metallic inorganic (acid gas) HAP. For the non-Hg metallic HAP, we chose to use PM as a surrogate. Most, if not all, non-Hg metallic HAP emitted from combustion sources will appear on the flue gas fly-ash. Therefore, the same control techniques that would be used to control the fly-ash PM will control non-Hg metallic HAP. PM was also chosen instead of specific metallic HAP because all fuels do not emit the same type and amount of metallic HAP but most generally emit PM that includes some amount and combination of all the metallic HAP. The use of PM as a surrogate will also eliminate the cost of performance testing to comply with numerous standards for individual non-Hg metals. Because non-Hg metallic HAP may preferentially partition to the small size particles (i.e., fine particle enrichment), we considered using $PM_{2.5}$ as the surrogate, but we determined that total PM (filterable (*i.e.,* $PM_{2.5}$) plus condensable) was the more appropriate surrogate for two reasons. The test method (201A) for measuring $PM_{2.5}$ is only applicable for use in exhaust stacks without entrained water droplets. Therefore, the test method for measuring $PM_{2.5}$ is not applicable for units equipped with wet scrubbers which are in use at many EGUs today and may be necessary at some additional units to achieve the proposed HCl emission limitations. Thus, we are proposing to use total PM, instead of $PM_{2.5}$, as the surrogate for non-Hg metals. However, as discussed elsewhere, we are also proposing alternative individual non-Hg metallic HAP emission limitations as well as total non-Hg metallic HAP emission limitations for all subcategories (total metal HAP emission limitation for the liquid oil-fired subcategory).

For non-metallic inorganic (acid gas) HAP, EPA is proposing setting an HCl standard and using HCl as a surrogate for the other non-metallic inorganic HAP for all subcategories except the liquid oil-fired subcategory. The emissions test information available to EPA indicate that the primary non-metallic inorganic HAP emitted from EGUs are acid gases, with HCl present in the largest amounts. Other inorganic compounds emitted are found in smaller quantities. As discussed earlier, control technologies that reduce HCl indiscriminately control other inorganic compounds such as Cl_2 and other acid gases (*e.g.,* HF, HCN, SeO_2). Thus, the best controls for HCl are also the best controls for other inorganic acid gas HAP. Therefore, HCl is a good surrogate for inorganic HAP because controlling HCl will result in control of other inorganic HAP emissions (as no liquid oil-fired EGU has an FGD system installed, there is no effective control in use and the surrogacy argument is invalid). As discussed elsewhere, EPA is also proposing to set an alternative equivalent SO_2 emission limit for coal-fired EGUs with some form of FGD system installed as: (1) The controls for SO_2 are also effective controls for HCl and the other acid gas-HAP; and (2) most, if not all, EGUs already have SO_2 CEMS in-place. Thus, SO_2 CEMS could serve as the compliance monitoring mechanism for such units. EGUs without an FGD system installed would not be able to use the alternate SO_2 emission limit, and EGUs must operate their FGD at all times to use the alternate SO_2 emission limit.

EPA is proposing work practice standards for non-dioxin/furan organic and dioxin/furan organic HAP. The significant majority of measured emissions from EGUs of these HAP were below the detection levels of the EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units. As the majority of measurements are so low, doubt is cast on the true levels of emissions that were measured during the tests. Overall, 1,552 out of 2,334, total test runs for dioxin/furan organic HAP contained data below the detection level for one or more congeners, or 67 percent of the entire data set. In several cases, all of the data for a given run were below the detection level; in few cases were the data for a given run all above the detection level. For the non-dioxin/furan organic HAP, for the individual HAP or constituent, between 57 and 89 percent of the run data were comprised of values below the detection level. Overall, the available test methods are technically challenged, to the point of providing results that are questionable for all of the organic HAP. For example, for the 2010 ICR testing, EPA extended the sampling time to 8 hours in an attempt to obtain data above the MDL. However, even with this extended sampling time, such data were not obtained making it questionable that any amount of effort, and, thus, expense, would make the tests viable. Based on the difficulties with accurate measurements at the levels of organic HAP encountered from EGUs and the economics associated with units trying to apply measurement methodology to test for compliance with numerical limits, we are proposing a work practice standard under CAA section 112(h).

We do not believe that this approach is inconsistent with that taken on other NESHAP where we also had issues with data at or below the MDL (*e.g.,* Portland Cement NESHAP; Boiler NESHAP). In the case of the Portland Cement NESHAP, the MDL issue was with HCl (a single compound HAP as opposed to the oftentimes multi-congener organic HAP), and in data from only 3 of 21 facilities. As noted elsewhere in this preamble, we dealt with similar MDL issues with HCl in establishing the limits in this proposed rule. In the case of the Boiler NESHAP, the MDL issue was with the organic HAP. For that rulemaking, the required sampling time during conducting of the associated ICR was 4 hours, as opposed to the 8 hours required in the 2010 ICR. Further, a review of the data indicates that the dioxin/furan HAP levels (a component of the organic HAP) were at least 7 times greater, on average, for coal-fired IB units and 3 times greater, on average, for oil-fired IB units than from similar EGUs. We think this difference is significant from a testing feasibility perspective.

For all the other HAP, as stated above, we are proposing to establish numerical emission rate limitations; however, we did consider using a percent reduction format for Hg (*e.g.,* the percent efficiency of the control device, the percent reduction over some input amount, *etc.*). We determined not to propose a percent reduction standard for several reasons. The percent reduction format for Hg and other HAP emissions would not have addressed EPA's desire to promote, and give credit for, coal preparation practices that remove Hg and other HAP before firing (*i.e.,* coal washing or beneficiation, actions that may be taken at the mine site rather than at the site of the EGU). Also, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s), and such an approach would be difficult to implement and enforce. In addition, we do not have the data necessary to establish percent reduction standards for HAP at this time. Depending on what was considered to be the "inlet" and the degree to which precombustion removal of HAP was desired to be included in the calculation, EPA would need (*e.g.*) the HAP content of the coal as it left the mine face, as it entered the coal preparation facility, as it left the coal preparation facility, as it entered the EGU, as it entered the control devices, and as it left the stack to be able to establish percent reduction standards. EPA believes, however, that an emission rate format allows for, and promotes, the use of precombustion HAP removal processes because such practices will help sources assure they will comply with the proposed standard. Furthermore, a percent reduction requirement would limit the flexibility of the regulated community by requiring the use of a control device. In addition, as discussed in the Portland Cement NESHAP (75 FR 55,002; September 9, 2010), EPA believes that a percent reduction format negates the contribution of HAP inputs to EGU performance and, thus, may be inconsistent with the DC Circuit Court's rulings as restated in *Brick MACT* (479 F.3d at 880) that say, in effect, that it is the emissions achieved in practice (*i.e.,* emissions to the atmosphere) that matter, not how one achieves those emissions. The 2010 ICR data confirm the point relating to plant inputs likely playing a role in emissions in that they indicate that some EGUs are achieving lower Hg emissions to the atmosphere at a lower Hg percent reduction (*e.g.,* 75 to 85 percent) than are other EGUs with higher percent reductions (*e.g.,* 90 percent or greater). For all of these reasons, we are proposing to establish numerical emission standards for HAP emissions from EGUs with the exception of the organic HAP standard which is in the form of work practices.

C. How did EPA determine the proposed emission limitations for existing EGUs?

All standards established pursuant to CAA section 112(d)(2) must reflect MACT, the maximum degree of reduction in emissions of air pollutants that the Administrator, taking into consideration the cost of achieving such emissions reductions, and any nonair quality health and environmental impacts and energy requirements, determines is achievable for each 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 which the Administrator has emissions information) for categories and subcategories with 30 or more sources or the best performing 5 sources for subcategories with less than 30 sources. This requirement determines the MACT floor for existing EGUs. However, EPA may not consider costs or other impacts in determining the MACT floor. EPA must consider cost, nonair quality health and environmental impacts, and energy requirements in connection with any standards that are more stringent than the MACT floor (beyond-the-floor controls).

D. How did EPA determine the MACT floors for existing EGUs?

EPA must consider available emissions information to determine the MACT floors. For each pollutant, we calculated the MACT floor for a subcategory of sources by ranking all the available emissions data obtained through the 2010 ICR[158] from units within the subcategory from lowest emissions to highest emissions (on a lb/MMBtu basis), and then taking the numerical average of the test results from the best performing (lowest emitting) 12 percent of sources.

Therefore, the MACT floor limits for each of the HAP and HAP surrogates are calculated based on the performance of the lowest emitting (best performing) sources in each of the subcategories.

As discussed above, for coal-fired EGUs, EPA established the MACT floors for non-Hg metallic HAP and non-metallic inorganic (acid gas) HAP based on sources representing 12 percent of the number of sources in the subcategory. For Hg from coal-fired units and all HAP from oil-fired units, EPA established the MACT floors based on sources representing 12 percent of the sources for which the Agency had emissions information. The IGCC and solid oil-fired EGU subcategories each have less than 30 units so the MACT floors were determined using the 5 best performing sources (or 2 sources for IGCC because there are only 2 such sources in the subcategory). The MACT floor limitations for each of the HAP and HAP surrogates (PM, Hg, and HCl) are calculated based on the performance of the lowest emitting (best performing) sources in each of the subcategories. The initial sort of the respective data to determine the MACT floor pool for analysis was made on the “lb/MMBtu” formatted data; this same pool of EGUs was then used for the “lb/MWh” analysis and all analyses were based on the data provided through the 2010 ICR.

We used the emissions data for those best performing affected sources to determine the emission limitations to be proposed, with an accounting for variability. EPA must exercise its judgment, based on an evaluation of the available data, to determine the level of emissions control that has been achieved by the best performing sources under variable conditions. The DC Circuit Court has recognized that EPA may consider variability in estimating the degree of emission reduction achieved by best-performing sources in setting MACT floors. *See Mossville Envt'l Action Now* v. *EPA,* 370 F.3d 1232, 1241–42 (DC Cir 2004) (holding EPA may consider emission variability in estimating performance achieved by best-performing sources and may set the floor at a level that best-performing source can expect to meet “every day and under all operating conditions”).

In determining the MACT floor limitations, we first determine the floor, which is the level achieved in practice by the average of the top 12 percent of similar sources for subcategories with more than 30 sources. We then assess variability of the best performers by using a statistical formula designed to estimate a MACT floor level that is achieved by the average of the best performing sources with some confidence (*e.g.,* 99 percent confidence) if the best performing sources were able to replicate the compliance tests in our data base. Specifically, the MACT floor limit is an upper prediction limit (UPL) calculated with the Student's t-test using the TINV function in Microsoft Excel. The Student's t-test has also been used in other EPA rulemakings (*e.g.,* NSPS for Hospital/Medical/Infectious Waste Incinerators; NESHAP for IB and Portland Cement) in accounting for variability. A prediction interval for a future observation, or an average of future observations, is an interval that will, with a specified degree of confidence, contain the next (or the average of some other pre-specified number of) randomly selected observation(s) from a population. In other words, the prediction interval estimates what the range of future values, or average of future values, will be, based upon present or past background samples taken. Given this definition, the UPL represents the value which we can expect the mean of three future observations (3-run average) to fall below, based upon the results of an independent sample from the same population. In other words, if we were to randomly select a future test condition from any of these sources (*i.e.,* average of 3 runs), we can be 99 percent confident that the reported level will fall at or below the UPL value. To calculate the UPL, we used the average (or sample mean) and an estimate of the standard deviation, which are two statistical measures calculated from the available data. The average is a measure of centrality of the distribution. Symmetric distributions such as the normal are centered around the average. The standard deviation is a common measure of the dispersion of the data set around the average.

We first determined the distribution of the emissions data for the best-performing 12 percent of units within each subcategory prior to calculating UPL values. When the sample size is 15 or larger, one can assume based on the Central Limit theorem, that the sampling distribution of the average or sampling mean of emission data is approximately normal, regardless of the parent distribution of the data. This assumption justifies selecting the normal-distribution based UPL equation for calculating the floor.

When the sample size is smaller than 15 and the distribution of the data is unknown, the Central Limit Theorem can't be used to support the normality assumption. Statistical tests of the kurtosis, skewness, and goodness of fit are then used to evaluate the normality assumption. To determine the distribution of the best performing dataset, we first computed the skewness and kurtosis statistics and then conducted the appropriate small-sample hypothesis tests. The skewness statistic (S) characterizes the degree of asymmetry of a given data distribution. Normally distributed data have a skewness of zero (0). A skewness statistic that is greater (less) than 0 indicates that the data are asymmetrically distributed with a right (left) tail extending towards positive (negative) values. Further, the standard error of the skewness statistic (SES) can be approximated by SES = SQRT(6/N) where N is the sample size. According to the small sample skewness hypothesis test, if S is greater than two times the SES, the data distribution can be considered non-normal. The kurtosis statistic (K) characterizes the degree of peakedness or flatness of a given data distribution in comparison to a normal distribution. Normally distributed data have a kurtosis of 0. A kurtosis statistic that is greater (less) than 0 indicates a

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[158] Earlier data were not used due to concerns related to changes in test and analytical methods.

relatively peaked (flat) distribution. Further, the standard error of the kurtosis statistic (SEK) can be approximated by SEK = SQRT(24/N) where N is the sample size. According to the small sample kurtosis hypothesis test, if K is greater than two times the SEK, the data distribution is typically considered to be non-normal.

The skewness and kurtosis hypothesis tests were applied to both the reported test values and the lognormal values (using the LN() function in Excel) of the reported test values. If S and K of the reported data set were both less than twice the SES and SEK, respectively, the dataset was classified as normally distributed. If neither S nor K, or only one of these statistics, were less than twice the SES or SEK, respectively, then we looked at the skewness and kurtosis hypothesis test results conducted for the natural log-transformed data. Then, the distribution most similar to a normal distribution was selected as the basis for calculating the UPL. If the results of the skewness and kurtosis hypothesis tests were mixed for the reported values and the natural log-transformed reported values, we chose the normal distribution to be conservative. We believe this approach is more accurate and obtained more representative results than a more simplistic normal distribution assumption.

Because some of the MACT floor emission limitations are based on the average of a 3-run test, and compliance with these limitations will be based on the same, the UPL for data considered to be normally distributed is calculated by:

$$UPL = \bar{x} + t(0.99, n-1) \times \sqrt{s^2 \times \left(\frac{1}{n} + \frac{1}{m}\right)}$$

Where:
n = the number of test runs
m = the number of test runs in the compliance average
□ = mean of the data from top performing sources calculated as

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

t(0.99, n–1) is the 99th percentile of the T-Student distribution with n–1 degrees of freedom
s^2 = variance of the data from top performing sources calculated as

$$s^2 = \frac{1}{n-1}\left\{\sum_{i=1}^{N}\left(x_i - \bar{x}\right)^2\right\}$$

This calculation was performed using the following Excel function:

Normal distribution: 99% UPL = AVERAGE(Test Runs in Top 12%) + [STDEV(Test Runs in Top 12%) × TINV(2 × probability, n–1 degrees of freedom)*SQRT((1/n)+(1/3))], for a one-tailed t-value (with 2 × probability), probability of 0.01, and sample size of n.

Data from only a single unit was used in establishing the new-source floor. Analysis based solely in these single-data-point-per-unit observations does not capture any within source variability. When additional information (*e.g.,* stack averages) from the past 5 years (from the 2010 ICR) was available, we combined the current and past data and calculated an estimate of the variance term, s^2, that intends to include the within and between source variability. The most recent data (*e.g.,* single floor average) were used to calculate the average in the UPL equation. The UPL equation for this case was calculated as:

$$\bar{x} + t_{df,.99}\sqrt{s^2\left(\frac{1}{N} + \frac{1}{m}\right)}$$

UPL =
Where:
m = the number of test runs in the compliance average
N = the number of units involved in calculating the average (a single measurement (*e.g.,* floor average) per unit)
n_i = number of data points (*e.g.,* stack averages) collected in the past for the i^{th} source

$$n = N + \sum_{i=1}^{N} n_i$$

number of data points (floor average plus stack averages) available to calculate the variance
df = n − 1
x_i = current information (*e.g.,* single floor average) for the i^{th} source
y_i = past information (*e.g.,* stack average) for the i^{th} source
m = the number of future test runs in the compliance average
□ = mean of the data from top performing sources calculated as

$$\bar{x} = \frac{1}{N}\sum_{i=1}^{N} x_i$$

$\bar{\bar{x}}$ is the grand mean (mean of the current and past information from the top performing sources) calculated as

$$\bar{\bar{x}} = \frac{1}{n}\left(\sum_{i=1}^{N} x_i + \sum_{i=1}^{N}\sum_{j=1}^{n_i} y_i\right)$$

s^2 = variance calculated as

$$s^2 = \frac{1}{n-1}\left\{\sum_{i=1}^{N}\left(x_i - \bar{\bar{x}}\right)^2 + \sum_{i=1}^{N}\sum_{j=1}^{n_i}\left(y_{ij} - \bar{\bar{x}}\right)^2\right\}$$

$t_{df,.99}$ = quantile t-distribution with *df* degrees of freedom at 99 percent confidence level *df* = degrees of freedom = n − 1

The calculation of this UPL was performed using the following Excel function:

Normal distribution: 99% UPL = AVERAGE(Test Runs in Top 12%) + [STDEV(Test Runs in Top 12%, stack averages) × TINV(2 × probability, (n–1) degrees of freedom)*SQRT((1/N)+(1⁄3))], for a one-tailed t-value (with 2 × probability), probability of 0.01, and sample size of n.

The UPL, to test compliance based on a 3-run average and assuming log-normal data, is calculated by (Bhaumik and Gibbons, 2004):

$$UPL = e^{\hat{\mu}+\frac{\hat{\sigma}^2}{2}} + \frac{z_{.99}}{m}\sqrt{me^{2\hat{\mu}+\hat{\sigma}^2}\left(e^{\hat{\sigma}^2}-1\right) + m^2e^{2\hat{\mu}+\hat{\sigma}^2}\left(\frac{\hat{\sigma}^2}{n}+\frac{\hat{\sigma}^4}{2(n-1)}\right)}$$

Where:

m = the number of test runs in the compliance average

n = the number of test runs

$\hat{\mu}$ = the average of the log transformed data from the top performing sources calculated as

$$\hat{\mu} = \frac{\sum_{i=1}^{n}\log\left(y_i\right)}{n}$$

$\hat{\sigma}$ = the variance estimate of the log transformed data from the top performing sources calculated as:

$$\hat{\sigma}^2 = \frac{\sum_{i=1}^{n}\left(\log\left(y_i\right)-\hat{\mu}\right)^2}{n-1}$$

z_{99} = the 99th-percentile of the log-normal distribution estimated using the trapezoidal rule approach from the following equation

$$\int_{0}^{z_{.99}}\left(1-\frac{\sqrt{\beta_{1z}}}{6}\left(3z-z^3\right)+\frac{\left(\beta_{2z}-3\right)\left(3-6z^2+z^4\right)}{24}\right)\phi(z) = .99$$

The calculation of the log-normal based UPL was performed using the following Excel function:

Normal distribution: 99% UPL = EXP(AVERAGE(LN(Test Runs in Top 12%)) + VAR(LN(Test Runs in Top 12%))/2) + (99TH-PERCENTILE LOGNORMAL DISTRIBUTION/m)*

SQRT(m*EXP(2* AVERAGE(LN(Test Runs in Top 12%))+ VAR(LN(Test Runs in Top 12%)))*(EXP(VAR(LN(Test Runs in Top 12%)))-1)+m∧2* EXP(2* AVERAGE(LN(Test Runs in Top 12%))+ VAR(LN(Test Runs in Top 12%)))*(VAR(LN(Test Runs in Top 12%))/n+ VAR(LN(Test Runs in Top 12%))∧2/(2*(n–1)))).

The 99th percentile of the log-normal distribution, $z_{.99}$, was calculated following Bhaumik and Gibbons (2004).

Test method measurement imprecision can also be a component of data variability. At very low emissions levels, as encountered in some of the data used to support this proposed rule, the inherent imprecision in the pollutant measurement method has a large influence on the reliability of the data underlying the regulatory floor or beyond-the-floor emissions limit. Of particular concern are those data that are reported near or below a test method's pollutant detection capability. In our guidance for reporting pollutant emissions used to support this proposed rule, we specified the criteria for determining test-specific MDL. Those criteria ensure that there is about a 1 percent probability of an error in deciding that the pollutant measured at the MDL is present when in fact it was absent. Such a probability is also called a false positive or the alpha, Type I, error. Another view of this probability is that one is 99 percent certain of the presence of the pollutant measured at the MDL. Because of matrix effects, laboratory techniques, sample size, and other factors, MDLs normally vary from test to test. We requested sources to identify (*i.e.,* flag) data which were measured below the MDL and to report those values as equal to the test-specific MDL.

Variability of data due to measurement imprecision is inherently and reasonably addressed in calculating the floor emissions limit when the data distribution, which would include the results of all tests, is significantly above the MDL. Should the data distribution shift such that some or many test results are below the MDL but are reported as MDL values, as is the case for some of our database, then other techniques need to be used to account for data variability. Indeed, under such a shift, the distribution becomes truncated on the lower end, leading to an artificial overabundance of values occurring at the MDL. Such an artificial overabundance of values could, if not adjusted, lead to erroneous floor calculations; those unadjusted floor calculations may be higher than otherwise expected, because no values reported below the MDL are included in the calculation. There is a concern that a floor emissions limit based on a truncated data base may not account adequately for data measurement variability and that a floor emissions limit calculated using values at or near the MDL may not account adequately for data measurement variability, because the measurement error associated with those values provides a large degree of uncertainty—up to 100 percent.

Despite our concern that accounting for measurement imprecision should be an important consideration in calculating the floor emissions limit, we did not adjust the calculated floor for the data used for this proposed rule because we do not know how to develop such an adjustment. We remain open to considering approaches for making such an adjustment, particularly when those approaches acknowledge our inability to detect with certainty those values below the MDL. We request comment on approaches suitable to account for measurement variability in establishing the floor emissions limit when based on measurements at or near the MDL.

As noted above, the confidence level that a value measured at the detection level is greater than 0 is about 99 percent. The expected measurement imprecision for an emissions value occurring at or near the MDL is about 40 to 50 percent. Pollutant measurement imprecision decreases to a consistent relative 10 to 15 percent for values measured at a level about three times the MDL.[159] One approach that we believe could be applied to account for measurement variability would require defining a MDL that is representative of the data used in establishing the floor emissions limitations and also minimizes the influence of an outlier test-specific MDL value. The first step in this approach would be to identify the highest test-specific MDL reported in a data set that is also equal to or less than the floor emissions limit calculated for the data set. This approach has the advantage of relying on the data collected to develop the floor emissions limit while to some degree minimizing the effect of a test(s) with an inordinately high MDL (*e.g.,* the sample volume was too small, the laboratory technique was insufficiently sensitive, or the procedure for determining the detection level was other than that specified).

The second step would be to determine the value equal to three times the representative MDL and compare it to the calculated floor emissions limit. If three times the representative MDL were less than the calculated floor emissions limit, we would conclude that measurement variability is adequately addressed and we would not adjust the calculated floor emissions limit. If, on the other hand, the value equal to three times the representative MDL were greater than the calculated floor emissions limit, we would conclude that the calculated floor emissions limit does not account entirely for measurement variability. We then would use the value equal to three times the MDL in place of the calculated floor emissions limit to ensure that the floor emissions limit accounts for measurement variability. This adjusted value would ensure measurement variability is adequately addressed in the floor or the emissions limit. This check was part of the variability analysis for all new MACT floors that had below detection level (BDL) or detection level limited (DLL) run data present in the best controlled data set and resulted in the MACT floors being three times the MDL rather than the UPL in a limited number of instances (see "MACT Floor Analysis (2011) for the Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units" (MACT Floor Memo) in the docket). We request comment on this approach.

As previously discussed, we account for variability in setting floors, not only because variability is an element of performance, but because it is reasonable to assess best performance over time. For example, we know that the HAP emission data from the best performing units are, for the most part, short-term averages, and that the actual HAP emissions from those sources will vary over time. If we do not account for this variability, we would expect that even the units that perform better than the floor on average could potentially exceed the floor emission levels a part of the time which would mean that variability was not properly taken into account. This variability may include the day-to-day variability in the total fuel-borne HAP input to each unit; variability of the sampling and analysis methods; and variability resulting from site-to-site differences for the best

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[159] American Society of Mechanical Engineers, *Reference Method Accuracy and Precision (ReMAP): Phase 1, Precision of Manual Stack Emission Measurements,* CRTD Vol. 60, February 2001.

performing units. EPA's consideration of variability accounted for that variability exhibited by the data representing multiple units and multiple data values for a given unit (where available). We calculated the MACT floor based on the UPL (upper 99th percentile) as described earlier from the average performance of the best performing units, Student's t-factor, and the variability of the best performing units.

We believe this approach reasonably ensures that the emission limits selected as the MACT floors adequately represent the level of emissions actually achieved by the average of the units in the top 12 percent, considering operational variability of those units. Both the analysis of the measured emissions from units representative of the top 12 percent, and the variability analysis, are reasonably designed to provide a meaningful estimate of the average performance, or central tendency, of the best controlled 12 percent of units in a given subcategory.

A detailed discussion of the MACT floor methodology is presented in the MACT Floor Memo in the docket.

1. Determination of MACT for the Fuel-borne HAP for Existing Sources

In developing the proposed MACT floor for the fuel-borne HAP (non-Hg metals, acid gases, and Hg), as described earlier, we are using PM as a surrogate for non-Hg metallic HAP (except for the liquid oil-fired subcategory) and HCl as a surrogate for the acid gases (except for the liquid oil-fired subcategory). Table 12 of this preamble presents the number of units in each of the subcategories, along with the number of units comprising the best performing units (top 12 percent). Table 12 of this preamble also shows the average emission level of the top 12 percent, and the MACT floor including consideration of variability (99 percent UPL of top 12 percent).

TABLE 12—SUMMARY OF MACT FLOOR RESULTS FOR EXISTING SOURCES

Subcategory	Parameter	PM	HCl	Mercury
Coal-fired unit designed for coal ≥ 8,300 Btu/lb.	No. of sources in subcategory	1,091	1,091	1,061.
	No. in MACT floor	131	131	40.
	Avg. of top 12%	0.02 lb/MMBtu	0.0003 lb/MMBtu	0.01 lb/TBtu.
	99% UPL of top 12%	0.030 lb/MMBtu	0.0020 lb/MMBtu	1.0 lb/TBtu.
Coal-fired unit designed for coal < 8,300 Btu/lb.	No. of sources in subcategory	1,091	1,091	30.
	No. in MACT floor	131	131.	2. 1.*
	Avg. of top 12%	0.02 lb/MMBtu	0.0003 lb/MMBtu	1 lb/TBtu. (1 lb/TBtu *).
	99% UPL of top 12%	0.030 lb/MMBtu	0.0020 lb/MMBtu	11.0 lb/TBtu. (4.0 lb/TBtu *).
IGCC	No. of sources in subcategory	2	2	2.
	No. in MACT floor	2	2	2.
	Avg.	0.03 lb/MMBtu	0.0002 lb/MMBtu	0.9 lb/TBtu.
	99% UPL	0.050 lb/MMBtu	0.00050 lb/MMBtu	3.0 lb/TBtu.
Solid oil-derived	No. of sources in subcategory	10	10	10.
	No. in MACT floor	5	5	5.
	Avg. of top 5	0.04 lb/MMBtu	0.002 lb/MMBtu	0.09 lb/TBtu.
	99% UPL of top 5	0.20 lb/MMBtu	0.0050 lb/MMBtu	0.20 lb/TBtu.
		Total metals **	HCl	Mercury.
Liquid oil	No. of sources in subcategory	154	154	154.
	No. in MACT floor	7	7	7.
	Avg. of top 12%	0.00002 lb/MMBtu	0.0001 lb/MMBtu	NA.
	99% UPL of top 12%	0.000030 lb/MMBtu	0.00030 lb/MMBtu	NA.

* Beyond-the-floor limit as discussed elsewhere.
** Includes Hg.
NA = Not applicable.

For the "Coal-fired unit designed for coal < 8,300 Btu/lb" subcategory, we used 12 percent of the available data (11 data points), or 2 units, in setting the existing source floor for Hg. For the IGCC subcategory, we used data from both units in setting the existing source floor. For the oil-fired subcategory, we did not include data obtained from EGUs co-firing natural gas in the existing-source MACT floor analysis because those emissions are not representative of EGUs firing 100 percent fuel oil.

We believe that chlorine may not be a compound generally expected to be present in oil. The ICR data that we have received suggests that in at least some oil, it is in fact present. EPA requests comment on whether chlorine would be expected to be a contaminant in oil and if not, why it is appearing in the ICR data. To the extent it would not be expected, we are taking comment on the appropriateness of an HCl limit. Further, we are proposing a total metals limit for oil-fired EGUs that includes Hg, in lieu of a PM limit, based on compliance through fuel analysis. We solicit comment on whether a PM limit or a total metals limit based on stack testing is an appropriate alternative. We recognize that PM is not an appropriate surrogate for Hg because Hg is not controlled to the same extent by the technologies which control emissions of other HAP metals, but we are soliciting comment as to whether there is anything unique as to oil-fired EGUs that would allow us to conclude that PM is an appropriate surrogate for all HAP metal emissions from such units. We further solicit comment on whether we should be setting a separate standard for Hg if we require end-of-stack testing for a total metals limit. Based on the data we have, that Hg limit would be 0.050 lb/MMBtu (0.000070 lb/GWh) for existing oil-fired units and 0.00010 lb/GWh for new oil-fired units. In this regard, we request additional Hg emissions data from oil-fired EGUs. Although we have some data, additional data would aid in our development of the standards for such units.

2. Determination of the Work Practice Standard

CAA section 112(h)(1) states that the Administrator may prescribe a work practice standard or other requirements, consistent with the provisions of CAA sections 112(d) or (f), in those cases where, in the judgment of the Administrator, it is not feasible to enforce an emission standard. CAA section 112(h)(2)(B) further defines the term "not feasible" in this context to apply when "the application of measurement technology to a particular class of sources is not practicable due to technological and economic limitations."

As noted earlier, the significant majority of the measured emissions from EGUs of dioxin/furan and non-dioxin/furan organic HAP are at or below the MDL of the EPA test methods even though we required 8 hour test runs. As such, EPA considers it impracticable to reliably measure emissions from these units. As mentioned earlier, because the expected measurement imprecision for an emissions value occurring at or near the MDL is about 40 to 50 percent, we are uncertain of the true levels of organic HAP emissions that would be obtained during any test program. Overall, the fact that the organic HAP emission levels found at EGUs are so near the MDL achievable by the available test methods indicates that the results obtained are questionable for all of the organic HAP.

Because the levels of organic HAP emissions from EGUs are so low (at or below the MDL of the available test methods), there is no indication that expending additional cost (*i.e.,* extending the sampling time) would provide the regulated community the ability to test for these HAP that would provide reliable, technically viable results. In fact, the 2010 ICR testing required a longer testing period than normally used and the results were still predominantly below the MDL. Because of the technical infeasibility, the economic infeasibility is that sources do not have a way to demonstrate compliance that is legitimate and we conclude no additional cost will improve the results.

Based on this analysis, and considering the fact that regardless of the cost, the resulting emissions data would be suspect due to the detection level issues, the Administrator is proposing under CAA section 112(h) that it is not feasible to enforce emission standards for dioxin/furan and non-dioxin/furan organic HAP because of the technological and economic infeasibility described above. Thus, a work practice, as discussed below, is being proposed to limit the emission of these HAP for existing EGUs.

For existing units, the only work practice we identified that would potentially control these HAP emissions is an annual performance test. Organic HAP are formed from incomplete combustion of the fuel. The objective of good combustion is to release all the energy in the fuel while minimizing losses from combustion imperfections and excess air. The combination of the fuel with the O_2 requires temperature (high enough to ignite the fuel constituents), mixing or turbulence (to provide intimate O_2-fuel contact), and sufficient time (to complete the process), sometimes referred to the three Ts of combustion. Good combustion practice (GCP), in terms of combustion units, could be defined as the system design and work practices expected to minimize the formation and maximize the destruction of organic HAP emissions. We maintain that the proposed work practice standards will promote good combustion and thereby minimize the organic HAP emissions we are proposing to regulate in this manner.

E. How did EPA consider beyond-the-floor options for existing EGUs?

Once the MACT floors were established for each subcategory, we considered various regulatory options more stringent than the MACT floor level of control (*i.e.,* technologies or other work practices that could result in lower emissions) for the different subcategories.

Except for one subcategory, we could not identify better HAP emissions reduction approaches that could achieve greater emissions reductions of HAP than the control technology combination(s) (*e.g.,* FF, carbon injection, scrubber, and GCP) that we expect will be used to meet the MACT floor levels of control (and that are already in use on EGUs comprising the top performing 12 percent of sources), though we did consider duplicate controls (*e.g.,* multiple scrubbers) in series and found the cost of that option unreasonable.

Fuel switching to natural gas is an option that would reduce HAP emissions. We determined that fuel switching was not an appropriate beyond-the-floor option. First, natural gas supplies are not available in some areas. Natural gas pipelines are not available in all regions of the U.S., and natural gas may not be available as a fuel for many EGUs. Moreover, even where pipelines provide access to natural gas, supplies of natural gas may not be adequate, especially during peak demand (*e.g.,* the heating season). Under such circumstances, there would be some units that could not comply with a requirement to switch to natural gas. While the combined capital cost and O&M costs for a coal-to-gas retrofit could be less than that of a combined retrofit with ACI and either DSI or FGD, the increased fuel costs of coal-to-gas cause its total incremental COE at a typical EGU is likely to be significantly larger than the incremental COE of the other retrofit options available. For example, an EPA analysis detailed in an accompanying TSD found that the incremental COE of coal-to-gas was 4 to 22 times the cost of alternatives, although the magnitude of the difference would change with alternative fuel price assumptions. EPA, therefore, concludes that the coal-to-gas option is not a cost-effective means of achieving HAP reductions for the purposes of this proposed rule.

Additional detail on the economics of coal-to-gas conversion and illustrative calculations of additional emission reductions versus cost impacts are provided in the "Coal-to-Gas Conversion" TSD in the docket.

As noted earlier, no EGU designed to burn a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in a EGU with a height-to-depth ratio of 3.82 or greater was found among the top performing 12 percent of sources for Hg emissions, even though some of these units employed ACI. EPA has learned that the units of this design that were using ACI during the testing were using ACI to meet their permitted Hg emission levels. However, EPA believes that the control level being achieved is still not that which could be achieved if ACI were used to its fullest extent. Therefore, EPA is proposing to establish a beyond-the-floor emission limit for existing EGUs designed to burn a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in a EGU with a height-to-depth ratio of 3.82 or greater. The proposed emission limit is 4 lb/TBtu for existing EGUs in this class. This proposed emission limit is based on use of the data from the top performing unit in the subcategory made available to the Agency through the 2010 ICR; the same statistical analyses were conducted as were done to establish the MACT floor values for the other HAP. EPA notes that our analysis shows that the technology installed to achieve the MACT floor limit would be the same technology used to achieve the beyond-the-floor MACT limit and, thus, proposing to go beyond-the-floor is reasonable. EPA solicits comment on whether it is appropriate to propose a beyond-the-floor limit for existing EGUs in this subcategory.

To assess the impacts on the existing EGUs in this subcategory to implement the proposed beyond-the-floor limit, EPA conducted analyses using approaches as discussed in the memoranda "Beyond-the-Floor Analysis (2011) for the Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units" and "Emission Reduction Costs for the Beyond-the-Floor Mercury Rate in the Toxics Rule" in the docket. The cost effectiveness of the beyond-the-floor option ranged from $17,375 to $21,393/lb Hg removed in the two approaches. The total costs of the non-air environmental impacts for the proposed beyond-the-floor limit for this subcategory are estimated as $12,310. Non-air quality health impacts were evaluated, but no incremental health impacts were attributable to installation of FF and ACI, because these technologies do not expose electric utility employees or the public to any additional health risks above the risks attributable to current utility operations involving compressed air systems, confined spaces, and exposure to fly ash.

EPA is aware that there may be other means of enhancing the removal of Hg from the flue gas stream (*e.g.,* spraying a halogen such as chlorine or bromine on the coal as it is fed to the EGU). EPA has information that indicates that such means were employed by an unknown number of EGUs during the period of time they were testing to provide data in compliance with the 2010 ICR (*see* McMeekin memo in the docket). Thus, we believe that the performance of such means is reflected in the MACT floor analysis. However, EPA has no data upon which to assess whether any other technology would provide additional control to that already shown by the use of ACI and, thus, we are not proposing to use such technologies as the basis for a beyond-the-floor analysis. EPA solicits comment on this approach.

EPA believes the best potential way of reducing Hg emissions from existing IGCC units is to remove Hg from the syngas before combustion. For example, an existing industrial coal gasification unit has demonstrated a process, using a sulfur-impregnated AC bed, which has proven to yield over 90 percent Hg removal from the coal syngas. (Rutkowski 2002.) We considered using carbon bed technology as beyond-the-floor for existing IGCC units. However, we have no detailed data to support this position at this time and, thus, are not proposing a beyond-the-floor limit for existing IGCC units. 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.

We considered proposing beyond-the-floor requirements for Hg in the other subcategories and for the other HAP in all of the subcategories. Activated carbon injection is used on EGUs designed for coal greater than or equal to 8,300 Btu/lb and, therefore, its effect on Hg removal has already been accounted for in the MACT floor. Further, EPA has no information that would indicate that ACI would provide significantly lower emission levels given the MACT floor Hg standard, and it is also possible that existing sources in this subcategory will utilize ACI to comply with the MACT floor limit. Activated carbon injection has not been demonstrated on liquid oil-fired EGUs. Similarly, ACI has not been demonstrated on solid oil-derived fuel-fired EGUs. EPA has no information that would indicate that ACI would provide significantly lower Hg emission levels on units operating at the level of the MACT floor. For the non-Hg metallic and acid gas HAP, there is no technology that would achieve additional control over that being shown by units making up the floor. Additional combinations of controls (*e.g.,* dual FGD systems in series) could be used but at a significant additional cost and, given the MACT floor level of control, a minimal additional reduction in HAP emissions. For the organic HAP, EPA is not aware of any measures beyond those proposed here that would result in lower emissions. Therefore, EPA is not proposing beyond-the-floor limitations other than as noted above.

F. Should EPA consider different subcategories?

EPA has attempted to identify subcategories that provide the most reasonable basis for grouping and estimating the performance of generally similar units using the available data. We believe that the subcategories we selected are appropriate.

EPA 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 and on the statutory constraint of "class, type or size"), how EPA should define any additional and/or 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 subcategories.

G. How did EPA determine the proposed emission limitations for new EGUs?

All standards established pursuant to CAA section 112 must reflect MACT, the maximum degree of reduction in emissions of air pollutants that the Administrator, taking into consideration the cost of achieving such emissions reductions, and any nonair quality health and environmental impacts and energy requirements, determines is achievable for each category. The CAA specifies that MACT for new EGUs shall not be less stringent than the emission control that is achieved in practice by the best-controlled similar source. This minimum level of stringency is the MACT floor for new units. However, EPA may not consider costs or other impacts in determining the MACT floor. EPA must consider cost, nonair quality health and environmental impacts, and energy requirements in connection with any standards that are more stringent than the MACT floor (beyond-the-floor controls).

H. How did EPA determine the MACT floor for new EGUs?

Similar to the MACT floor process used for existing EGUs, the approach for determining the MACT floor must be based on available emissions test data. Using such an approach, we calculated the MACT floor for a subcategory of sources by ranking the 2010 ICR emissions data from EGUs within the subcategory from lowest to highest (on a lb/MMBtu basis) to identify the best controlled similar source. The MACT floor limitations for each of the HAP and HAP surrogates (PM, Hg, and HCl) are calculated based on the performance (numerical average) of the lowest emitting (best controlled) source for each pollutant in each of the subcategories.

The MACT floor limitations for new sources were calculated using the same formula as was used for existing sources with one exception. For the new source calculations, the results of the three individual emission test runs were used instead of the 3-run average that was used in determining the existing-source MACT floor. This was done to be able to provide some measure of variability. As previously discussed, we account for variability of the best-controlled source in setting floors, not only because variability is an element of performance, but because it is reasonable to assess best performance over time. We calculated the MACT floor based on the UPL (upper 99th percentile) as described earlier from the average performance of the best controlled similar source, Student's t-factor, and the total variability of the best-controlled source.

This approach reasonably ensures that the emission limit selected as the MACT floor adequately represents the average level of control actually achieved by the best controlled similar source, considering ordinary operational variability.

A detailed discussion of the MACT floor methodology is presented in the MACT Floor Memo in the docket.

The approach that we use to calculate the MACT floors for new sources is somewhat different from the approach that we use to calculate the MACT floors for existing sources. Although the MACT floors for existing units are intended to reflect the performance achieved by the average of the best performing 12 percent of sources, the MACT floors for new units are meant to reflect the emission control that is achieved in practice by the best controlled similar source. Thus, for existing units, we are concerned about estimating the central tendency of a set of multiple units, whereas for new units, we are concerned about estimating the level of control that is representative of that achieved by a single best controlled source. As with the analysis for existing sources, the new EGU analysis must account for variability.

1. Determination of MACT for the Fuel-Borne HAP for New Sources

In developing the MACT floor for the fuel-borne HAP (PM, HCl, and Hg), as described earlier, we are using PM as a surrogate for non-Hg metallic HAP and HCl as a surrogate for the acid gases (except for the liquid oil-fired subcategory). Table 13 of this preamble presents for each subcategory and fuel-borne HAP the average emission level of the best controlled similar source and the MACT floor which accounts for variability (99 percent UPL).

TABLE 13—SUMMARY OF MACT FLOOR RESULTS FOR NEW SOURCES

Subcategory	Parameter	PM	HCl	Mercury
Coal-fired unit designed for coal ≥ 8,300 Btu/lb.	Avg. of top performer	0.03 lb/MWh	0.2 lb/GWh	0.00001 lb/GWh.
	99% UPL of top performer (test runs)	0.050 lb/MWh	0.30 lb/GWh	0.000010 lb/GWh.
Coal-fired unit designed for coal < 8,300 Btu/lb.	Avg. of top performer	0.03 lb/MWh	0.2 lb/GWh	0.02 lb/GWh.
	99% UPL of top performer (test runs)	0.050 lb/MWh	0.30 lb/GWh	0.040 lb/GWh.
IGCC	Avg. of top performer	N/A	N/A	N/A.
	99% UPL of top performer (test runs)	0.050 lb/MWh *	0.30 lb/GWh *	0.000010 lb/GWh.*
Solid oil-derived	Avg. of top performer	0.04 lb/MWh	0.0003 lb/MWh	0.0007 lb/GWh.
	99% UPL of top performer (test runs)	0.050 lb/MWh	0.00030 lb/MWh	0.0020 lb/GWh.
		Total metals **	HCl	Mercury
Liquid oil	Avg. of top performer	0.00009 lb/MMBtu.	0.0002 lb/MWh	NA.
	99% UPL of top performer (test runs)	0.00040 lb/MMBtu.	0.00050 lb/MWh	NA.

* Beyond-the-floor as discussed elsewhere.
** Includes Hg.
NA = Not applicable.

2. Determination of the Work Practice Standard

We are proposing a work practice standards for non-dioxin/furan organic and dioxin/furan organic HAP under CAA section 112(h) that would require the implementation of an annual performance test program for new EGUs. This proposal for new EGUs is based on the same reasons discussed previously for existing EGUs. That is, the measured emissions from EGUs of these HAP are routinely below the detection limits of the EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units.

Thus, the work practice discussed above for existing EGUs is being proposed to limit the emissions of non-dioxin/furan organic and dioxin/furan organic HAP for new EGUs.

We request comments on this approach.

I. How did EPA consider beyond-the-floor for new units?

The MACT floor level of control for new EGUs is based on the emission control that is achieved in practice by the best controlled similar source within each of the subcategories. No technologies were identified that would achieve HAP reduction greater than the new source floors for the subcategories, except for multiple controls in series (*e.g.,* multiple FFs) which we consider to be unreasonable from a cost perspective.

Fuel switching to natural gas is a potential regulatory option beyond the new source floor level of control that would reduce HAP emissions. However, natural gas supplies are not available in some areas. Thus, this potential control option may be unavailable to many sources in practice. Limited emissions reductions in combination with the high cost of fuel switching and considerations about the availability and technical feasibility of fuel switching makes this an unreasonable regulatory option that was not considered further. As discussed above, the uncertainties associated with nonair quality health and environmental impacts also argue against determining that fuel switching is reasonable beyond-the-floor option. In addition, even if we determined that natural gas supplies were available in all regions, we would still not adopt this fuel switching option because it would effectively prohibit new construction of coal-fired EGUs and we do not think that is a reasonable approach to regulating HAP emissions from EGUs.

Although, as discussed earlier for existing EGUs, EPA is proposing to establish a beyond-the-floor emission limit for Hg for existing EGUs designed to burn a nonagglomerating fuel having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in a EGU with a height-to-depth ratio of 3.82 or greater, EPA is not proposing to go beyond-the-floor for new EGUs in this subcategory. The proposed emission limit of 0.04 lb/GWh for new EGUs in this subcategory is based on use of ACI on a new unit and, we believe, reflects a level of performance achievable and, as noted above, no technologies were identified that would achieve HAP reduction greater than the new source floors for the subcategories, except for multiple controls in series (*e.g.,* multiple FFs) which we consider to be unreasonable from a cost perspective.

As discussed earlier, because of a lack of data, EPA is not proposing beyond-the-floor emission limits for existing IGCC units. However, EPA believes that the new-source limits derived from the data obtained from the two operating IGCC units are not representative of what a new IGCC unit could achieve. Therefore, EPA looked to the permit issued for the Duke Energy Edwardsport IGCC facility currently under construction.[160] The permitted limits for this unit are similar to the limits derived from the existing units. Because of advances in technology, EPA does not believe that even these permitted levels are representative of what a modern IGCC unit could achieve. The emissions from IGCC units are normally predicted to be similar to or lower than those from traditional pulverized coal (PC) boilers. For example, DOE projects that future IGCC units will be able to meet a PM (filterable) emissions limit of 0.0071 lb/MMBtu, a SO_2 emissions limit of 0.0127 lb/MMBtu, and a Hg emissions limit of 0.571 lb/TBtu.[161] Therefore, we are proposing that the new-source limits for new IGCC units be identical to those of new coal-fired units designed for coal greater than or equal to 8,300 Btu/lb. However, EPA has no information upon which to base the costs and non-air quality health, environmental, and energy impacts of this proposed approach. EPA solicits comment on this approach. Commenters should provide data that support their comment, including costs, emissions data, or engineering analyses.

Similarly, for the reasons discussed earlier for existing EGUs, EPA is not proposing any other beyond-the-floor emission limitations. EPA requests comments on whether the use of any control techniques have been demonstrated to consistently achieve emission levels that are lower than levels from similar sources achieving the proposed new-source MACT floor levels of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs, including retrofit costs.

J. Consideration of Whether To Set Standards for HCl and Other Acid Gas HAP Under CAA Section 112(d)(4)

We are proposing to set a conventional MACT standard for HCl and, for the reasons explained elsewhere, are proposing that the HCl limit also serve as a surrogate for other acid gas HAP. We also considered whether it was appropriate to exercise our discretionary authority to establish health-based emission standards under CAA section 112(d)(4) for HCl and each of the other relevant HAP acid gases: Cl_2, HF, SeO_2, and HCN[162] (because if it were regulated under CAA section 112(d)(4), HCl may no longer be the appropriate surrogate for these other HAP).[163] This section sets forth the requirements of CAA section 112(d)(4); our analysis of the information available to us that informed the decision on whether to exercise discretion; questions regarding the application of CAA section 112(d)(4); and our explanation of how this case relates to prior decisions EPA has made under CAA section 112(d)(4) with respect to HCl.

As a general matter, CAA section 112(d) requires MACT standards at least as stringent as the MACT floor to be set for all HAP emitted from major sources. However, CAA section 112(d)(4) provides that for HAP with established health thresholds, the Administrator has the discretionary authority to consider such health thresholds when establishing emission standards under CAA section 112(d). This provision is intended to allow EPA to establish emission standards other than conventional MACT standards, in cases where a less stringent emission standard will still ensure that the health threshold will not be exceeded, with an ample margin of safety. In order to exercise this discretion, EPA must first conclude that the HAP at issue has an established health threshold and must then provide for an ample margin of safety when considering the health threshold to set an emission standard.

It is clear the Administrator may exercise her discretionary authority under CAA section 112(d)(4) only with respect to pollutants with a health threshold. Where there is an established threshold, the Administrator interprets CAA section 112(d)(4) to allow her to weigh additional factors, beyond any established health threshold, in making a judgment whether to set a standard for a specific pollutant based on the threshold, or instead follow the traditional path of developing a MACT standard after determining a MACT floor. In deciding whether to exercise her discretion for a threshold pollutant for a given source category, the Administrator interprets CAA section 112(d)(4) to allow her to take into account factors such as the following: the potential for cumulative adverse health effects due to concurrent exposure to other HAP with similar biological endpoints, from either the same or other source categories, where the concentration of the threshold pollutant emitted from the given source category is below the threshold; the potential impacts on ecosystems of releases of the pollutant; and reductions in criteria pollutant emissions and other co-benefits that would be achieved by a MACT standard. Each of these factors is directly relevant to the health and environmental outcomes at which CAA section 112 is fundamentally aimed. If the Administrator does determine that it is appropriate to set a standard based on a health threshold, she must develop emission standards that will ensure the public will not be exposed to levels of the pertinent HAP in excess of the

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[160] Letter from Matthew Stuckey, State of Indiana, to Mack Sims, Duke Energy Indiana. Operating permit fo Edwardsport Generating Station IGCC. Undated.

[161] DOE. Overview—Bituminous & Natural Gas to Electricity; Overview of Bituminous Baseline Study. From: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL–2007/1281, May 2007.

[162] Before considering whether to exercise her discretion under CAA section 112(d)(4) for a particular pollutant, the Administrator must first conclude that a health threshold has been established for the pollutant.

[163] Hydrogen chloride can serve as a surrogate for the other acid gases in a technology-based MACT standard, because the control technology that would be used to control HCl would also reduce the other acid gases. By contrast, HCl would not be an appropriate surrogate for a health-based emission standard that is protective against the potential adverse health effects from the other acid gases, because these gases (*e.g.,* HF) can act on biological organisms in a different manner than HCl, and each of the acid gases affects human health with a different dose-response relationship.

health threshold, with an ample margin of safety.

EPA has exercised its discretionary authority under CAA section 112(d)(4) in a handful of prior rules setting emissions standards for other major source categories, including the Boiler NESHAP issued in 2004, which was vacated on other grounds by the DC Circuit Court. In the Pulp and Paper NESHAP (63 FR 18765; April 15, 1998), and Lime Manufacturing NESHAP (67 FR 78054; December 20, 2002), EPA invoked CAA section 112(d)(4) for HCl emissions for discrete units within the facility. In those rules, EPA concluded that HCl had an established health threshold (in those cases it was interpreted as the RfC for chronic effects) and HCl was not classified as a human carcinogen. In light of the absence of evidence of carcinogenic risk, the availability of information on non-carcinogenic effects, and the limited potential health risk associated with the discrete units being regulated, EPA concluded that it was appropriate to exercise its discretion under CAA section 112(d)(4) for HCl under the circumstances of those rules. EPA did not set an emission standard based on the health threshold; rather, the exercise of EPA's discretion in those cases in effect exempted HCl from the MACT requirement. In more recent rules, EPA decided not to propose a health-based emission standard for HCl emissions under CAA section 112(d)(4) for Portland Cement facilities (75 FR 54970 (September 9, 2010), and for Industrial, Commercial, and Institutional Boilers, (75 FR 32005; June 4, 2010 proposal(major); the final major source rule was signed on February 21, 2011 but has not yet been published). EPA has never implemented a NESHAP that used CAA section 112(d)(4) with respect to HF, Cl_2, SeO_2, or HCN.[164]

Because any emission standard under CAA section 112(d)(4) must consider the established health threshold level, with an ample margin of safety, in this rulemaking EPA has considered the adverse health effects of the HAP acid gases, beginning with HCl and including HF, Cl_2, SeO_2, and HCN. Research indicates that HCl is associated with chronic respiratory toxicity. In the case of HCl, this means that chronic inhalation of HCl can cause tissue damage in humans. Among other things, it is corrosive to mucous membranes and can cause damage to eyes, nose, throat, and the upper respiratory tract as well as pulmonary edema, bronchitis, gastritis, and dermatitis. Considering this respiratory toxicity, EPA has established a chronic RfC for the inhalation of HCl of 20 micrograms per cubic meter ($\mu g/m^3$). An RfC is defined as an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups[165]) that is likely to be without an appreciable risk of deleterious effects during a lifetime. The development of the RfC for HCl reflected data only on its chronic respiratory toxicity. It did not take into account effects associated with acute exposure,[166] and, in this situation, the IRIS health assessment did not evaluate the potential carcinogenicity of HCl (on which there are very limited studies). As a reference value for a single pollutant, the RfC also did not reflect any potential cumulative or synergistic effects of an individual's exposure to multiple HAP or to a combination of HAP and criteria pollutants. As the RfC calculation focused on health effects, it did not take into account the potential environmental impacts of HCl.

With respect to the potential health effects of HCl, we note the following:

(1) Chronic exposure to concentrations at or below the RfC is not expected to cause chronic respiratory effects;

(2) Little research has been conducted on its carcinogenicity. The one occupational study of which we are aware found no evidence of carcinogenicity;

(3) There is a significant body of scientific literature addressing the health effects of acute exposure to HCl (for a summary, *see* California Office of Health Hazard Assessment, 2008. Acute Toxicity Summary for Hydrogen Chloride, *http://www.oehha.ca.gov/air/hot_spots/2008/AppendixD2_final.pdf#page=112 EPA,* 2001). In addition, we note that several researchers have shown associations between acid gases and reduced lung function and asthma in North American children.[167] However, we currently lack information on the peak short-term emissions of HCl from EGUs, which might allow us to determine whether a chronic health-based emission standard for HCl would ensure that acute exposures will not pose any health concerns, and;

(4) We are aware of no studies explicitly addressing the toxicity of mixtures of HCl with other respiratory irritants. However, many of the other HAP (and criteria pollutants) emitted by EGUs also are respiratory irritants, and in the absence of information on interactions, EPA assumes an additive cumulative effect (Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures. *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=20533*). The fact that EGUs can be located in close proximity to a wide variety of industrial facilities makes predicting and assessing all possible mixtures of HCl and other emitted air pollutants difficult, if not impossible.

In addition to potential health impacts, the Administrator also has evaluated the potential for environmental impacts when considering whether to exercise her discretion under CAA section 112(d)(4). When HCl gas encounters water in the atmosphere, it forms an acidic solution of hydrochloric acid. In areas where the deposition of acids derived from emissions of sulfur and NO_X are causing aquatic and/or terrestrial acidification, with accompanying ecological impacts, the deposition of hydrochloric acid could exacerbate these impacts. Recent research[168] has suggested that deposition of airborne HCl has had a greater impact on ecosystem acidification than previously thought, although direct quantification of these impacts remains an uncertain process. We maintain it is appropriate to consider potential adverse environmental effects in addition to adverse health effects when setting an emission standard for HCl under CAA section 112(d)(4).

Because the statute requires an ample margin of safety, it would be reasonable to set any CAA section 112(d)(4) emission standard for a pollutant with a health threshold at a level that at least

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[164] EPA has not classified HF, Cl_2, SeO_2, or HCN with respect to carcinogenicity. However, at this time the Agency is not aware of any data that would suggest any of these HAP are carcinogens.

[165] "Sensitive subgroups" may refer to particular life stages, such as children or the elderly, or to those with particular medical conditions, such as asthmatics.

[166] California EPA considered acute toxicity and established a 1-hour reference exposure level (REL) of 2.1 milligrams per cubic meter (mg/m^3). An REL is the concentration level at or below which no adverse health effects are anticipated for a specified exposure duration. RELs are designed to protect the most sensitive individuals in the population by the inclusion of margins of safety.

[167] Dockery DW, Cunningham J, Damokosh AI, Neas LM, Spengler JD, Koutrakis P, Ware JH, Raizenne M, Speizer FE. 1996. Health Effects of Acid Aerosols on North American Children: Respiratory Symptoms. Environmental Health Perspectives 104(5):500–504; Raizenne M, Neas LM, Damokosh AI, Dockery DW, Spengler JD, Koutrakis P, Ware JH, Speizer FE. 1996. Health Effects of Acid Aerosols on North American Children: Pulmonary Function. Environmental Health Perspectives 104(5):506–514.

[168] Evans, CD, Monteith, DT, Fowler, D, Cape, JN, and Brayshaw, S. *Hydrochloric Acid: an Overlooked Driver of Environmental Change,* Env. Sci. Technol., DOI: 10.1021/es10357u.

assures that persons exposed to emissions of the pollutant would not experience the adverse health effects on which the threshold is based due to sources in the controlled category or subcategory. In the case of this proposed rulemaking, we have concluded that we do not have sufficient information at this time to establish what the health-based emission standards would be for HCl or the other acid gases from EGUs alone, much less for EGUs and other sources of acid gas HAP located at or near facilities with EGUs.

Finally, we considered the fact that setting conventional MACT standards for HCl as well as PM (as a surrogate for HAP metals) would result in significant reductions in emissions of other pollutants, most notably SO_2, PM, and other non-HAP acid gases (*e.g.,* hydrogen bromide) and would likely also result in additional reductions in emissions of Hg and other HAP metals (*e.g.,* Se). The additional reductions of SO_2 alone attributable to the proposed limit for HCl are estimated to be 2.1 million tons in the third year following promulgation of the proposed HCl standard. These are substantial reductions with substantial public health benefits. Although NESHAP may directly address only HAP, not criteria pollutants, Congress did recognize, in the legislative history to CAA section 112(d)(4), that NESHAP would have the collateral benefit of controlling criteria pollutants as well and viewed this as an important benefit of the air toxics program.[169] Therefore, even where EPA concludes a HAP has a health threshold, the Agency may consider the collateral benefits of controlling criteria pollutants as a factor in determining whether to exercise its discretion under CAA section 112(d)(4).

Given the limitations of the currently available information (*e.g.,* the HAP mix where EGUs are located, and the cumulative impacts of respiratory irritants from nearby sources), the environmental effects of HCl and the other acid gas HAP, and the significant co-benefits of setting a conventional MACT standard for HCl and the other acid gas HAP, the Administrator is proposing not to exercise her discretion to use CAA section 112(d)(4).

This conclusion is not contrary to EPA's prior decisions noted earlier where we found it appropriate to exercise the discretion to invoke the authority in CAA section 112(d)(4) for HCl, because the circumstances in this case differ from previous considerations. EGUs differ from the other source categories for which EPA has exercised its authority under CAA section 112(d)(4) in ways that affect consideration of any health threshold for HCl. EGUs are much more likely to be significant emitters of acid gas HAP and non-HAP than are other source categories. In fact, they are the largest anthropogenic emitter of HCl and HF in the U.S, emitting roughly half of the estimated nationwide total HCl and HF emissions in 2010. Our case study analyses of the chronic impacts of EGUs did not indicate any significant potential for them to cause any exceedances of the chronic RfC for HCl due to their emissions alone.[170] However, we do not have adequate information on the other acid gas HAP to include them in our analysis, and did not consider their impacts in concert with other emitters of HCl (such as IB units) to develop estimates of cumulative exposures to HCl and other acid gas HAP in the vicinity of EGUs. In addition, EGUs may be located at facilities in heavily populated urban areas where many other sources of HAP exist. These factors make an analysis of the health impact of emissions from these sources on the exposed population significantly more complex than for many other source categories, and, therefore, make it more difficult to establish an ample margin of safety without significantly more information. Absent the information necessary to provide a credible basis for developing alternative health-based emission standards for all acid gases, and for all the other reasons discussed above, EPA is choosing not to exercise its discretion under CAA section 112(d)(4) for these pollutants from EGUs.

K. How did we select the compliance requirements?

We are proposing testing, monitoring, notification, and recordkeeping requirements that are adequate to assure continuous compliance with the requirements of this proposed rule. These requirements are described elsewhere in this preamble. We selected these requirements based upon our determination of the information necessary to ensure that the emission standards and work practices are being followed and that emission control devices and equipment are maintained and operated properly. These proposed requirements ensure compliance with this proposed rule without imposing a significant additional burden for units that must implement them.

We are proposing that units using continuous monitoring systems for PM, HCl, and Hg demonstrate initial compliance by performance testing for non-Hg HAP metals and the surrogate PM, for HCl and its surrogate SO_2, and for Hg, and then to perform subsequent performance testing every 5 years for non-Hg HAP metals and PM and for HCl and SO_2. To ensure continuous compliance with the proposed Hg emission limits in-between the performance tests, this proposed rule would require coal-fired units to use either CEMS or sorbent trap monitoring systems, with an option for very low emitters to use a less rigorous method based on periodic stack testing. These requirements are found in proposed Appendix A to 40 CFR part 63, subpart UUUUU. For PM and HCl, affected units that elect to install CEMS would use the CEMS to demonstrate continuous compliance. However, units equipped with devices that control PM and HCl emissions but do not elect to use CEMS, would determine suitable parameter operating limits, to monitor those parameters on a continuous basis, and to conduct emissions testing every other month. Units combusting liquid oil on a limited basis would, upon request and approval, be allowed to determine limits for metals, chlorine, and Hg concentrations in fuel and to measure subsequent fuel metals, chlorine, and Hg concentrations monthly; and low emitting units would be allowed to determine limits for metals, chlorine, and Hg concentrations in fuel and to measure subsequent fuel metals, chlorine, and Hg concentrations monthly.

Additionally, this proposed rule would require annual maintenance be performed so that good combustion continues. Such an annual check will serve to ensure that dioxins, furans, and other organic HAP emissions continue to be at or below MDLs.

We evaluated the feasibility and cost of applying PM CEMS to EGUs. Several electric utility companies in the U.S. have now installed or are planning to install PM CEMS. In recognition of the fact that PM CEMS are commercially available, EPA developed and promulgated PSs for PM CEMS (69 FR 1786, January 12, 2004). Performance Specifications for PM CEMS are established under PS 11 in appendix B to 40 CFR part 60 for evaluating the acceptability of a PM CEMS used for determining compliance with the emission standards on a continuous basis. For PM CEMS monitoring, initial costs were estimated to be $261,000 per

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[169] *See* S. Rep. No. 101–228, 101st Cong. 1st sess. At 172.

[170] For those facilities modeled, the hazard index for HCl ranged from 0.05 to 0.005 (see Non-Hg Case Study Chronic Inhalation Risk Assessment for the Utility MACT "Appropriate and Necessary" Analysis in the docket).

unit and annualized costs were estimated to be $91,000 per unit. We determined that requiring PM CEMS for EGUs combusting coal or oil is a reasonable monitoring option. We are requesting comment on the application of PM CEMS to EGUs, and the use of data from such systems for compliance determinations under this proposed rule.

Table 14 holds preliminary cost information. Note that these costs are based on 2010 ICR emissions test estimates and on values in EPA's monitoring costs assessment tool. Particulate matter and metals and SO_2 and HCl testing includes surrogacy testing initially and every 5 years, parameter monitoring includes testing every two months, and fuel content monitoring includes annual testing.

TABLE 14—COST INFORMATION

	Initial costs, $K	Annual costs, $K	
Metals			
PM CEMS	261	91	
Fabric filter	61	109	
ESP	59	114	
Acid Gases			
SO_2 CEMS	232	66	None if existing CEMS used.
HCl CEMS	233	57	
Dry sorbent injection	10	144	Plus material costs.
Wet scrubber	9	143	
Mercury			
Hg CEMS	271	110	
Sorbent traps	23	128	Minimum of 52 traps and analysis per year.
Fuel analysis	10	49	
Dioxin/furan and non-dioxin/furan organic HAP			
Tune up	17	3	

The Agency is seeking comment on the cost information presented above. The commenters are encouraged to provide detailed information and data that will help the Agency refine its cost estimates for this rulemaking.

The majority of test methods that this proposed rule would require for the performance stack tests have been required under many other EPA standards. Three applicable voluntary consensus standards were identified: American Society of Mechanical Engineers (ASME) Performance Test Code (PTC) 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," a manual method for measuring the oxygen, CO_2, and CO content of exhaust gas; ASTM Z65907, "Standard Method for Both Speciated and Elemental Mercury Determination," a method for Hg measurement; and ASTM Method D6784–02 (Ontario Hydro), a method for measuring Hg. The majority of emissions tests upon which the proposed emission limitations are based were conducted using these test methods.

When a performance test is conducted, we are proposing that parameter operating limitations be determined during the tests. Performance tests to demonstrate compliance with any applicable emission limitations are either stack tests or fuel analysis or a combination of both.

To ensure continuous compliance with the proposed emission limitations and/or operating limits, this proposed rule would require continuous parameter monitoring of control devices and recordkeeping. We selected the following requirements based on reasonable cost, ease of execution, and usefulness of the resulting data to both the owners or operators and EPA for ensuring continuous compliance with the emission limitations and/or operating limits.

We are proposing that certain parameters be continuously monitored for the types of control devices commonly used in the industry. These parameters include pH, pressure drop and liquid flow rate for wet scrubbers; and sorbent injection rate for dry scrubbers and DSI systems. You must also install a BLDS for FFs. These monitoring parameters have been used in other standards for similar industries. The values of these parameters are established during the initial or most recent performance test that demonstrates compliance. These values are your operating limits for the control device.

You would be required to set parameters based on 4-hour block averages during the compliance test, and demonstrate continuous compliance by monitoring 12-hour block average values for most parameters. We selected this averaging period to reflect operating conditions during the performance test to ensure the control system is continuously operating at the same or better level as during a performance test demonstrating compliance with the emission limits.

To demonstrate continuous compliance with the emission and operating limits, you would also need daily records of the quantity, type, and origin of each fuel burned and hours of operation of the affected source. If you are complying with the chlorine fuel input option, you must keep records of the calculations supporting your determination of the chlorine content in the fuel.

If a liquid oil-fired EGU elected to demonstrate compliance with the HCl or individual or total HAP metal limit by using fuel which has a statistically lower pollutant content than the emission limit, we are proposing that the source's operating limit is the emission limit of the applicable pollutant. Under this option, a source is not required to conduct performance stack tests. If a source demonstrates compliance with the HCl, individual or total PM, or Hg limit by using fuel with a statistically higher pollutant content than the applicable emission limit, but performance tests demonstrate that the source can meet the emission limitations, then the source's operating limits are the operating limits of the control device (if used) and the fuel pollutant content of the fuel type/mixture burned.

This proposed rule would specify the testing methodology and procedures and the initial and continuous compliance requirements to be used when complying with the fuel analysis options. Fuel analysis tests for total chloride, gross calorific value, Hg, individual and total HAP metal, sample collection, and sample preparation are included in this proposed rule.

If you are a liquid oil-fired EGU and elect to comply based on fuel analysis, you will be required to statistically analyze, using the z-test, the data to determine the 90th percentile confidence level. It is the 90th percentile confidence level that is required to be used to determine compliance with the applicable emission limit. The statistical approach is required to assist in ensuring continuous compliance by statistically accounting for the inherent variability in the fuel type.

We are proposing that a source be required to recalculate the fuel pollutant content only if it burns a new fuel type or fuel mixture and conduct another performance test if the results of recalculating the fuel pollutant content are higher than the level established during the initial performance test.

L. What alternative compliance provisions are being proposed?

We are proposing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for units at the affected source that are within a single subcategory.

As part of EPA's general policy of encouraging the use of flexible compliance approaches where they can be properly monitored and enforced, we are including emissions averaging in this proposed rule. Emissions averaging can provide sources the flexibility to comply in the least costly manner while still maintaining regulation that is workable and enforceable. Emissions averaging would not be applicable to new affected sources and could only be used between EGUs in the same subcategory at a particular affected source. Also, owners or operators of existing sources subject to the EGU NSPS (40 CFR part 60, subparts D and Da) would be required to continue to meet the PM emission standard of that NSPS regardless of whether or not they are using emissions averaging.

Emissions averaging would allow owners and operators of an affected source to demonstrate that the source complies with the proposed emission limits by averaging the emissions from an individual affected unit that is emitting above the proposed emission limits with other affected units at the same facility that are emitting below the proposed emission limits and that are within the same subcategory.

This proposed rule includes an emissions averaging compliance alternative because emissions averaging represents an equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels. We have concluded that a limited form of averaging could be implemented that would not lessen the stringency of the MACT floor limits and would provide flexibility in compliance, cost and energy savings to owners and operators. We also recognize that we must ensure that any emissions averaging option can be implemented and enforced, will be clear to sources, and most importantly, will be no less stringent than unit by unit implementation of the MACT floor limits.

EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging within an affected source across individual affected units subject to the standard under certain conditions. Averaging across affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the NESHAP will not be greater under the averaging mechanism than it could be if each individual affected unit complied separately with the applicable standard. Under this test, the practical outcome of averaging is equivalent to compliance with the MACT floor limits by each discrete unit, and the statutory requirement that the MACT standard reflect the maximum achievable emissions reductions is, therefore, fully effectuated.

In past rulemakings, EPA has generally imposed certain limits on the scope and nature of emissions averaging programs. These limits include: (1) No averaging between different types of pollutants; (2) no averaging between sources that are not part of the same affected source; (3) no averaging between individual sources within a single major source if the individual sources are not subject to the same NESHAP; and (4) no averaging between existing sources and new sources.

This proposed rule would fully satisfy each of these criteria. First, emissions averaging would only be permitted between individual sources at a single existing affected source, and would only be permitted between individual sources subject to the proposed EGU NESHAP. Further, emissions averaging would not be permitted between two or more different affected sources. Finally, new affected sources could not use emissions averaging. Accordingly, we have concluded that the averaging of emissions across affected units is consistent with the CAA. In addition, this proposed rule would require each facility that intends to utilize emission averaging to submit an emission averaging plan, which provides additional assurance that the necessary criteria will be followed. In this emission averaging plan, the facility must include the identification of: (1) All units in the averaging group; (2) the control technology installed; (3) the process parameter that will be monitored; (4) the specific control technology or pollution prevention measure to be used; (5) the test plan for the measurement of the HAP being averaged; and (6) the operating parameters to be monitored for each control device. Upon receipt, the regulatory authority would not be able to approve an emission averaging plan containing averaging between emissions of different types of pollutants or between sources in different subcategories.

This proposed rule would also exclude new affected sources from the emissions averaging provision. EPA believes emissions averaging is not appropriate for new affected sources because it is most cost effective to integrate state-of-the-art controls into equipment design and to install the technology during construction of new sources. One reason we allow emissions averaging is to give existing sources flexibility to achieve compliance at diverse points with varying degrees of add-on control already in place in the most cost-effective and technically reasonable fashion. This flexibility is not needed for new affected sources because they can be designed and constructed with compliance in mind.

In addition, we seek comment on use of a discount factor when emissions averaging is used and on the appropriate value of a discount factor, if used. Such discount factors (*e.g.,* 10 percent) have been used in previous NESHAP, particularly where there was variation in the types of units within a common source category to ensure that the environmental benefit was being achieved. In this situation, however, the affected sources are more homogeneous, making emissions averaging a more straight-forward analysis. Further, with the monitoring and compliance provisions that are being proposed, there is additional assurance that the environmental benefit will be realized. Further, the emissions averaging provision would not apply to individual units if the unit shares a common stack with units in other subcategories, because in that circumstance it is not possible to distinguish the emissions from each individual unit.

The emissions averaging provisions in this proposed rule are based in part on the emissions averaging provisions in the Hazardous Organic NESHAP (HON). The legal basis and rationale for the HON emissions averaging provisions were provided in the preamble to the final HON.[171]

M. How did EPA determine compliance times for this proposed rule?

CAA section 112 specifies the dates by which affected sources must comply with the emission standards. New or reconstructed units must be in compliance with this proposed rule immediately upon startup or [DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER], whichever is later. Existing sources may be provided up to 3 years to comply with the final rule; if an existing source is unable to comply within 3 years, a permitting authority has the discretion to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls. *See* section 112(i)(3). We believe that 3 years for compliance is necessary to allow adequate time to design, install and test control systems that will be retrofitted onto existing EGUs, as well as obtain permits for the use of add-on controls.

We believe that the requirements of the proposed rule can be met without adversely impacting electric reliability. Our analysis shows that the expected number of retirements is less than many have predicted and that these can be managed effectively with existing tools and processes for ensuring continued grid reliability. Further, the industry has adequate resources to install the necessary controls and develop the modest new capacity required within the compliance schedule provided for in the CAA. Although there are a significant number of controls that need to be installed, with proper planning, we believe that the compliance schedule established by the CAA can be met. There are already tools in place (such as integrated resource planning, and in some cases, advanced auctions for capacity) that ensure that companies adequately plan for, and markets are responsive to, future requirements such as the proposed rule. In addition, EPA itself has already begun reaching out to key stakeholders including not only sources with direct compliance obligations, but also groups with responsibility to assure an affordable and reliable supply of electricity including state Public Utility Commissions (PUC), Regional Transmission Organizations (RTOs), the National Electric Reliability Council (NERC), the Federal Energy Regulatory Commission (FERC), and DOE. EPA intends to continue these efforts during both the development and implementation of this proposed rule. It is EPA's understanding that FERC and DOE will work with entities whose responsibility is to ensure an affordable, reliable supply of electricity, including state PUCs, RTOs, the NERC to share information and encourage them to begin planning for compliance and reliability as early as possible. This effort to identify and respond to any projected local and regional reliability concerns will inform decisions about the timing of retirements and other compliance strategies to ensure energy reliability. EPA believes that the ability of permitting authorities to provide an additional 1 year beyond the 3-year compliance time-frame as specified in CAA section 112, along with other compliance tools, ensures that the emission reductions and health benefits required by the CAA can be achieved while safeguarding completely against any risk of adverse impacts on electricity system reliability. Between proposal and final, EPA will work with DOE and FERC to identify any opportunities offered by the authorities and policy tools at the disposal of DOE and/or FERC that can be pursued to further ensure that the dual goals of substantially reducing the adverse public health impacts of power generation, as required by the CAA, while continuing to assure electric reliability is maintained. EPA also intends to continue to work with DOE, FERC, state PUCs, RTOs and power companies as this rule is implemented to identify and address any challenges to ensuring that both the requirements of the CAA and the need for a reliable electric system are met.

In developing this proposed rule, EPA has performed specific analysis to assess the feasibility (*e.g.,* ability of companies to install the required controls within the compliance time-frame) and potential impact of the proposed rule on reliability.

With regards to feasibility, EPA used IPM to project what types of controls would need to be installed to meet the requirements of this proposed rule. This includes technologies to control acid gases (wet and dry scrubber technology and the use of sorbent injection), the Hg requirements (co-benefits from other controls such as scrubbers and FFs and Hg-specific controls such as ACI), the non-Hg metal requirements (upgrades and or replacements of existing particulate control devices), and other HAP emissions (GCP).

Much of the power sector already has controls in place that remove significant amounts of acid gases. Today over 50 percent of the power generation fleet has scrubbing technology installed and the industry is already working on installations to bring that number to nearly two-thirds of the fleet by 2015. Many of the remaining coal-fired units are smaller, burn lower sulfur coals, and/or do not operate in a base-load mode. Units with these types of characteristics are candidates to use DSI technology which takes significantly less time to install. Units that choose to install dry or wet scrubbing technology should be able to do so within the compliance schedule required by the CAA as this technology can be installed within the 3-year window.[172] Notably, EPA does not project use of wet scrubbing technology to meet the requirements of this proposed rule and that is the technology that typically takes a longer time to install.

For Hg control, those units that do not meet the requirements with existing controls have several options. Companies with installed scrubbers may be able to make modifications (such as the use of scrubber additives to enhance Hg control). Other companies may use supplemental controls such as ACI. These types of options all take significantly less than 3 years to install.

Units that do not meet the non-Hg metal HAP requirements have several options such as upgrading existing particulate controls, installing

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[171] Hazardous Organic NESHAP (59 FR 19425; April 22, 1994).

[172] In a letter to Senator Carper dated November 3, 2010 (*http://www.icac.com/files/public/ICAC_Carper_Response_110310.pdf*) David Foerter, the executive director of the Institute of Clean Air Companies (ICAC) explained that wet scrubber technology could be installed in 36 months, dry scrubber technology could be installed in 24 months and dry sorbent injection could be installed in 12 months. Page 3.

supplemental particulate controls, or replacing existing particulate controls. These options can also be implemented in significantly less than 3 years.

EPA projects that for acid gas control, companies will likely use dry scrubbing and sorbent injection technologies rather than wet scrubbing. For non-Hg metal HAP controls, EPA has assumed that companies with ESPs will likely upgrade them to FFs. As a number of units that were in the MACT floor for non-Hg HAP metals only had ESPs installed, this is likely a conservative assumption. For Hg, EPA projects that companies will comply through either the collateral reductions created by other controls (*e.g.,* scrubber/SCR combination) or ACI. EPA has assessed the feasibility of installing these controls within the compliance window (see TSD) and believes that the controls can be reasonably installed within that time. Although EPA assessed the ability to install the controls in 3 years (and determined that the controls could be installed in that time-frame), this would require the control technology industry to ramp up quickly. Therefore, EPA also assessed a time-frame that would allow some installations to take up to 4 years. This time-frame is consistent with the CAA which allows permitting authorities the discretion to grant extensions to the compliance time-line of up to 1 year. This time-frame also allows for staggered installation of controls at facilities that need to install technologies on multiple units. Staggered installation allows companies to address such issues as scheduling outages at different units so that reliable power can be provided during these outage periods or particularly complex retrofits (*e.g.,* when controls for one unit need to be located in an open area needed to construct controls on another unit). In other words, the additional 1-year extension would provide an additional two shoulder periods to schedule outages. It also provides additional opportunity to spread complex outages over multiple outage periods. EPA believes that while many units will be able to fully comply within 3 years, the 4th year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary.

Permitting authorities are familiar with the operation of this provision because they have used it in implementing previous NESHAP. This extension can be used to address a range of reasons that installation schedules may take more than 3 years including: staggering installations for reliability or constructability purposes, or other site-specific challenges that may arise related to source-specific construction issues, permitting, or local manpower or resource challenges. EPA is proposing that States consider applying this extension both to the installation of add on controls (*e.g.,* a FF, or a dry scrubber) and the construction of on-site replacement power (*e.g.,* a case when a coal unit is being shut down and the capacity is being replaced on-site by another cleaner unit such as a combined cycle or simple cycle gas turbine and the replacement process requires more than 3 years to accomplish). EPA believes that it is reasonable to allow the extension to apply to the replacement because EPA believes that building of replacement power could be considered “installation of controls” at the facility. Because the phrase “installation of controls” could also be interpreted to apply only to changes made to an existing unit rather than the replacement of that existing unit with a new cleaner one, EPA takes comment on its proposal to allow the extension to apply to replacement power.

EPA has also considered the impact that potential retirements under this proposed rule will have on reliability. When considering the impact that one specific action has on power plant retirements, it is important to understand that the economics that drive retirements are based on multiple factors including: Expected electric demand, cost of alternative generation, and cost of continuing to generate using an existing unit. EPA's analysis shows that the lower cost of alternative generating sources (particularly the cost of natural gas), as well as reductions in demand, have a greater impact on the number of projected retirements than does the impact of the proposed rule. EPA's assessment looked at the reserve margins in each of 32 subregions in the continental U.S. It shows that with the addition of very little new capacity, average reserve margins are significantly higher than required (NERC assumes a default reserve margin of 15 percent while the average capacity margin seen after implementation of the policy is nearly 25 percent). Although such an analysis does not address the potential for more localized transmission constraints, the number of retirements projected suggests that the magnitude of any local retirements should be manageable with existing tools and processes. Demand forecasts used were based on EIA projected demand growth.

Reliability concerns caused by local transmission constraints can be addressed through a range of solutions including the development of new generation and/or demand side resources, and/or enhancements to the transmission system. On the supply side, there are a range of options including the development of more centralized power resources (either base-load or peaking), and/or the development of cogeneration, or distributed generation. Even with the large reserve margins, there are companies ready to implement supply side projects quickly. For instance, in the PJM Interconnection (an RTO) region, there are over 11,600 MW of capacity that have completed feasibility and impact studies and could be on-line by the third quarter of 2014.[173] Demand side options include energy efficiency as well as demand response programs. These types of resources can also be developed very quickly. In 2006, PJM Interconnection had less than 2,000 MWs of capacity in demand side resources. Within 4 years this capacity nearly quadrupled to almost 8,000 MW of capacity.[174] Recent experience also shows that transmission upgrades to address reliability issues from plant closures can also occur in less than 3 years. In addition to helping address reliability concerns, reducing demand through mechanisms such as energy efficiency and demand side management practices has many other benefits. It can reduce the cost of compliance and has collateral air quality benefits by reducing emissions in periods where there are peak air quality concerns.

EPA also examined the impact on reliability of unit outages to install control equipment. Because these outages usually occur in the shoulder months (outside summer or winter peaking periods) when demand is lower (and, thus, reserve margins are higher), the analysis showed that even with conservative estimates regarding the length of the outages and conservative estimates about how many outages occurred within a 1-year time-frame, reserve margins were maintained. With the potential for a 1-year compliance extension, outages can be further staggered, providing additional flexibility, even if some units require longer outages.

Although EPA's analysis shows that there is sufficient time and grid capacity to allow for compliance with the rule within the 3-year compliance window

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[173] Paul M Sotkiewicz, PJM Interconnection, Presentation at the Bipartisan Policy Commission Workshop Series on Environmental Regulation and Electric System Reliability, Workshop 3: Local, State, Regional and Federal Solutions, January 19, 2011, Washington DC, *http://www.bipartisanpolicy.org/sites/default/files/Paul%20Sotkiewicz-%20Panel%202_0.pdf*, slide 6.

[174] Ibid—slide 5.

(with the possibility of a 1-year extension), to achieve compliance in a timely fashion, EPA expects that sources will begin promptly, based upon this proposed rule, to evaluate, select, and plan to implement, source-specific compliance options. In doing so, we would expect sources to consider the following factors: if retirement is the selected compliance option, notifying any relevant RTO/ISO in advance in order to develop an appropriate shutdown plan that identifies any necessary replacement power transmission upgrades or other actions necessary to ensure consistent electric supply to the grid; if installation of control technologies is necessary, any source-specific space limitations, such that installation can be staggered in a timely fashion; and source-specific electric supply requirements, such that outages can be appropriately scheduled. Starting assessments early and considering the full range of options is prudent because it will help ensure that the requirements of this proposed rule are met as economically as possible and that power companies are able to provide reliable electric power.

There is significant evidence that companies do in fact engage in such forward planning. For instance, in September of 2004 (approximately 6 months before the CAIR and CAMR requirements were finalized); Cinergy announced that it had already begun a construction program to comply. This program involved not only preliminary engineering, but actual construction of scrubbers.[175] Southern Company also began its engineering process well before those rules were finalized.[176] Although EPA understands that not every generating company may commit to actual capital projects in advance of finalization of the rule, the CAIR experience shows that some companies do. Even if companies do not take the step of committing to the capital projects, there are actions that companies can take that are much less costly. Companies can analyze their unit-by-unit compliance options based on the proposed rule. This will put them in a position to begin construction of projects with the longest lead times quickly and will ensure that the 3-year compliance window (or 4 with extension from the permitting authority) can be met.

It will also ensure that sufficient notification can be provided to RTOs/ISOs so that the full range of options for addressing any reliability concerns can be considered. Although most RTOs/ISOs only require 90-day notifications for retirements, construction schedules for all but the simplest retrofits will be longer, so sources should be able to notify their RTOs of their retirements earlier. This will also help as multiple sources work with their RTO/ISO to determine outage schedules. The RTOs/ISOs also have a very important role to play and it appears that a number of them are already engaged in preparing for these rules. For instance, PJM Interconnection considered the impact of these anticipated rules at its January 14, 2011, Regional Planning Process Task Force Meeting,[177] and Midwest Independent Transmission System Operator, Inc. (MISO) has also begun a planning process to consider the impact of EPA rules.[178]

As discussed above, given the large reserve margins that exist, even after consideration of requirements of the proposed rule, EPA believes that any reliability issues are likely to be primarily local in nature and be due to the retirement of a unit in a load constrained area. As demonstrated by the work that PJM Interconnection and MISO are doing, RTOs/ISOs are required to do long range (at least 10 years) capacity planning that includes consideration of future requirements such as EPA regulations. Furthermore, if companies within an RTO/ISO wish to retire a unit, they must first notify the RTO/ISO in advance so that any reliability concerns can be addressed. The RTOs/ISOs, have well established procedures to address such retirements.

Starting assessments early and considering the full range of options will help ensure that the requirements of this rule are met as economically as possible and that power companies are able to provide reliable electric power while significantly reducing their impact on public health. For power companies this includes considering the range of pollution control options available for their existing fleet as well as considering the range of options for replacement power, in the cases where shutting down a unit is the more economic choice. The RTOs/ISOs should consider the full range of options to provide any necessary replacement power including the development of both supply and demand side resources. Environmental regulators should work with their affected sources early to understand their compliance choices. In this way, those regulators will be able to accurately access when use of the 1-year compliance extension is appropriate. By working with regulators early, affected sources will be in a position to have assurance that the 1-year extension will be granted in those situations where it is appropriate.

Section X.c. describes the sensitivity analysis performed by EPA for an Energy Efficiency case, in which a combination of DOE appliance standards and State investments in demand-side efficiency come into place at the same time as compliance with the requirements of this rule. That analysis shows that even in the absence of this rule, moderate actions to promote energy efficiency would lead to retirement of an additional 11 GW in 2015, of 27 GW in 2020, and of 26 GW in 2030, beyond the capacity already projected to retire in the base case. In effect, the timely adoption and implementation of energy efficiency policies would augment currently projected reserve capacities that are instrumental to assuring system reliability.

As noted, instrumental to undertaking such actions are other Federal agencies such as DOE, ISOs and RTOs, and state agencies such as PUCs. Fortunately, in addition to helping to assure system reliability, timely implementation of energy efficiency policies offer these key decision-makers an additional incentive to take action. As the analysis shows, energy efficiency can reduce costs for ratepayers and customers.

First, with or without the proposed Toxic Rule, energy efficiency policies are shown by the analysis to reduce the overall costs of generating electricity, with the cost reductions increasing over time. *See* Table 22. Second, when comparing the Toxics Rule Case without energy efficiency to the Toxics Rule Case with energy efficiency, the analysis suggests that if these energy efficiency policies were to be put into place and maintained over time by system operators, states and DOE, the costs of the proposed Toxics Rule are mitigated by these cost reductions such that the overall system costs are reduced by $2 billion in 2015, $6 billion in 2020, and $11 billion in 2030.

The energy savings driven by these energy efficiency policies mean that consumers will pay less for electricity as well. EPA has modeled national average retail electricity prices, including the energy efficiency costs that are paid by the ratepayer. The Toxics Rule increases retail prices by 3.7 percent, 2.6 percent and 1.9 percent in 2015, 2020 and 2030

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[175] Cinergy Press Release, September 2nd, 2004, "Cinergy Operating Companies to Reduce Power Plant Emissions, Improve Air Quality."

[176] ICAC.

[177] Paul M Sotkiewicz, PJM Interconnection, "Consideration of Forthcoming Environmental Regulations in the Planning Process," January 14, 2011.

[178] MISO Planning Advisory Committee, "Proposed EPA Regulatory Impact Analysis," November 23, 2010.

respectively relative to the base case. If energy efficiency policies are implemented along with the Toxics Rule, the average retail price of electricity increases by 3.3 percent in 2015 relative to the base case, but falls relative to the base case by about 1.6 percent in 2020 and about 2.3 percent in 2030. The effect on electricity bills however may fall more than these percentages suggest as energy efficiency means that less electricity will be used by consumers of electricity.

EPA believes that as it shares these results with PUCs, the commissions will respond in accordance with their ongoing imperative to ensure that electricity costs for ratepayers and consumers remains stable. Specifically, the opportunity created through the deployment of energy efficiency-promoting strategies and initiatives to safeguard system reliability and, especially, to curb cost increases that might otherwise result from implementation of the Toxics Rule should provide PUCs with both the motivation and the justification for providing utilities with the financial and regulatory support they need to begin planning as early as possible for compliance and to incorporate in their plans the kinds of energy efficiency investments needed to achieve both compliance and cost-minimization.

EPA recognizes that both utilities and their regulators often are hesitant to take early action to comply with environmental standards because they avoid incurring costs that they fear may not be required once the final regulation is promulgated. EPA urges utilities and regulators to begin planning and preparations for timely compliance. The same concerns about consumer cost in some cases also dissuade utilities from incurring, and commissions from authorizing, the upfront costs associated with energy efficiency programs. However, EPA also believes that if it takes steps to actively disseminate the results of the energy efficiency analysis, then utilities will be that much more likely to begin, and regulators that much more likely to support, comprehensive assessment and planning as early as possible since compliance approaches that encompass energy efficiency integrated with other actions needed to meet the Toxics Rule's requirements will result in lower costs for ratepayers and consumers. EPA encourages State environmental regulators to consider the extent to which a utility engages in early planning when making a decision regarding granting a 4th year for compliance with the Toxics Rule.

In summary, EPA believes that the large reserve margins, the range of control options, the range of flexibilities to address unit shutdowns, existing processes to assure that sufficient generation exists when and where it is needed, and the flexibilities within the CAA, provide sufficient assurance that the CAA section 112 requirements for the power sector can be met without adversely impacting electric reliability.

EGUs are the subject of several rulemaking efforts that either are or will soon be underway. In addition to this rulemaking proposal, concerning both hazardous air pollutants under section 112 and criteria pollutant NSPS standards under section 111, EGUs are the subject of other rulemakings, including ones under section 110(a)(2)(D) addressing the interstate transport of emissions contributing to ozone and PM air quality problems, coal combustion wastes, and the implementation of section 316(b) of the Clean Water Act (CWA). They will also soon be the subject of a rulemaking under CAA section 111 concerning emissions of greenhouse gases.

EPA recognizes that it is important that each and all of these efforts achieve their intended environmental objectives in a common-sense manner that allows the industry to comply with its obligations under these rules as efficiently as possible and to do so by making coordinated investment decisions and, to the greatest extent possible, by adopting integrated compliance strategies. In addition, EO 13563 states that "[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote such coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation." Thus, EPA recognizes that it needs to approach these rulemakings, to the extent that its legal obligations permit, in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that the rulemakings must achieve.

The upcoming rulemaking under section 111 regarding GHG emissions from EGUs may provide an opportunity to facilitate the industry's undertaking integrated compliance strategies in meeting the requirements of these rulemakings. First, since that rulemaking will be finalized after a number of the other rulemakings that are currently underway are, the Agency will have an opportunity to take into account the effects of the earlier rulemakings in making decisions regarding potential GHG standards for EGUs.

Second, in that rulemaking, EPA will be addressing both CAA section 111(b) standards for emissions from new and modified EGUs and CAA section 111(d) emission guidelines for states to follow in establishing their plans regarding GHG emissions from existing EGUs. In evaluating potential emission standards and guidelines, EPA may consider the impacts of other rulemakings on both emissions of GHGs from EGUs and the costs borne by EGUs. The Agency expects to have ample latitude to set requirements and guidelines in ways that can support the states' and industry's efforts in pursuing practical, cost-effective and coordinated compliance strategies encompassing a broad suite of its pollution-control obligations. EPA will be taking public comment on such flexibilities in the context of that rulemaking.

As discussed elsewhere in this preamble, we invite comment on this proposed rule. EPA solicits comment on the ability of sources subject to this proposed rule to comply within the statutorily mandated 3-year compliance window and/or the 1-year discretionary extension, as well as comment on specific factors that could prevent a source from achieving, or could enable a source to achieve, compliance. In addition, EPA requests comment on the impact of this proposed rule on electric reliability, and ways to ensure compliance while maintaining the reliability of the grid.

A number of states (or localities) have proactively developed plans to address a suite of environmental issues, an aging generation fleet, and electric reliability (*e.g.,* plans requiring retirement of coal and pollution control devices such as the Colorado "Clean Air-Clean Jobs Act" or renewable portfolio standards that because of the states' current generation mix could result in significant changes to the composition of the fossil-fuel-fired portion of the fleet such as Hawaii's renewable portfolio standard (HB–1464)). In most cases, these plans were developed solely under State law with no underlying Federal requirement. Furthermore, as explained above, many of the technologies that were installed or that are planned to be installed in response to these state plans are likely to result in collateral reductions of many HAP required to be reduced in today's proposed rule. Although some of these state programs may have obtained some important emission reductions to date, they may also allow compliance time-frames for some units that extend beyond those authorized under CAA section 112(i)(3).

The Agency has a program pursuant to 40 CFR subpart E, whereby states can take delegation of section 112 emission standards. Among other things, states can seek approval of state rules to the extent they can demonstrate that those rules are no less stringent that the applicable section 112(d) rule. Because overall, some of these state programs may result in greater emission reductions, EPA is taking comment on whether (and if so how) such state plans could be integrated with the proposed rule requirements consistent with the statute. EPA also intends to engage with states who believe that they have such plans to understand whether they believe that there are opportunities to integrate the two sets of requirements in a manner consistent with the requirements of the CAA.

EGUs are the subject of several rulemaking efforts that either are or will soon be underway. In addition to this rulemaking proposal, concerning both HAP under section 112 and criteria pollutant NSPS standards under section 111, EGUs are the subject of other rulemakings, including ones under section 110(a)(2)(D) addressing the interstate transport of emissions contributing to ozone and PM air quality problems, coal combustion wastes, and the implementation of section 316(b) of the CWA. They will also soon be the subject of a rulemaking under CAA section 111 concerning emissions of greenhouse gases (GHG).

EPA recognizes that it is important that each and all of these efforts achieve their intended environmental objectives in a common-sense manner that allows the industry to comply with its obligations under these rules as efficiently as possible and to do so by making coordinated investment decisions and, to the greatest extent possible, by adopting integrated compliance strategies. Thus, EPA recognizes that it needs to approach these rulemakings, to the extent that its legal obligations permit, in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that the rulemakings must achieve.

The upcoming rulemaking under section 111 regarding GHG emissions from EGUs may provide an opportunity to facilitate the industry's undertaking integrated compliance strategies in meeting the requirements of these rulemakings. First, since that rulemaking will be finalized after a number of the other rulemakings that are currently underway are, the agency will have an opportunity to take into account the effects of the earlier rulemakings in making decisions regarding potential GHG standards for EGUs.

Second, in that rulemaking, EPA will be addressing both CAA section 111(b) standards for emissions from new and modified EGUs and CAA section 111(d) emission guidelines for states to follow in establishing their plans regarding GHG emissions from existing EGUs. In evaluating potential emission standards and guidelines, EPA may consider the impacts of other rulemakings on both emissions of GHGs from EGUs and the costs borne by EGUs. The Agency expects to have ample latitude to set requirements and guidelines in ways that can support the states' and industry's efforts in pursuing practical, cost-effective and coordinated compliance strategies encompassing a broad suite of its pollution-control obligations. EPA will be taking public comment on such flexibilities in the context of that rulemaking.

N. How did EPA determine the required records and reports for this proposed rule?

You would be required to comply with the applicable requirements in the NESHAP General Provisions, subpart A of 40 CFR part 63, as described in Table 10 of the proposed 40 CFR part 63, subpart UUUUU. We evaluated the General Provisions requirements and included those we determined to be the minimum notification, recordkeeping, and reporting requirements necessary to ensure compliance with, and effective enforcement of, this proposed rule.

We would require additional recordkeeping if you chose to comply with the chlorine or Hg fuel input option. You would need to keep records of the calculations and supporting information used to develop the chlorine or Hg fuel input operating limit.

O. How does this proposed rule affect permits?

The CAA requires that sources subject to this proposed rule be operated pursuant to a permit issued under EPA-approved state operating permit program. The operating permit programs are developed under Title V of the CAA and the implementing regulations under 40 CFR parts 70 and 71. If you are operating in the first 2 years of the current term of your operating permit, you will need to obtain a revised permit to incorporate this proposed rule. If you are in the last 3 years of the current term of your operating permit, you will need to incorporate this proposed rule into the next renewal of your permit.

P. Alternative Standard for Consideration

As discussed above, we are proposing alternate equivalent emission standards (for certain subcategories) to the proposed surrogate standards in three areas: SO_2 (in addition to HCl), individual non-Hg metals (for PM), and total non-Hg metals (for PM). The proposed emission limitations are provided in Tables 16 and 17 of this preamble.

TABLE 15—ALTERNATE EMISSION LIMITATIONS FOR EXISTING COAL- AND OIL-FIRED EGUS

Subcategory	Coal-fired unit designed for coal ≥ 8,300 Btu/lb	Coal-fired unit designed for coal < 8,300 Btu/lb	IGCC, lb/TBtu (lb/GWh)	Liquid oil, lb/TBtu (lb/GWh)	Solid oil-derived
SO_2	0.20 lb/MMBtu (2.0 lb/MWh).	0.20 lb/MMBtu (2.0 lb/MWh).	NA	NA	0.40 lb/MMBtu (5.0 lb/MWh).
Total non-Hg metals	0.000040 lb/MMBtu (0.00040 lb/MWh).	0.000040 lb/MMBtu (0.00040 lb/MWh).	5.0 (0.050)	NA	0.000050 lb/MMBtu (0.001 lb/MWh).
Antimony, Sb	0.60 lb/TBtu (0.0060 lb/GWh).	0.60 lb/TBtu (0.0060 lb/GWh).	0.40 (0.0040)	0.20 (0.0030)	0.40 lb/TBtu (0.0070 lb/GWh).
Arsenic, As	2.0 lb/TBtu (0.020 lb/GWh).	2.0 lb/TBtu (0.020 lb/GWh).	2.0 (0.020)	0.60 (0.0070)	0.40 lb/TBtu (0.0040 lb/GWh).
Beryllium, Be	0.20 lb/TBtu (0.0020 lb/GWh).	0.20 lb/TBtu (0.0020 lb/GWh).	0.030 (0.0030)	0.060 (0.00070)	0.070 lb/TBtu (0.00070 lb/GWh).
Cadmium, Cd	0.30 lb/TBtu (0.0030 lb/GWh).	0.30 lb/TBtu (0.0030 lb/GWh).	0.20 (0.0020)	0.10 (0.0020)	0.40 lb/TBtu (0.0040 lb/GWh).

TABLE 15—ALTERNATE EMISSION LIMITATIONS FOR EXISTING COAL- AND OIL-FIRED EGUS—Continued

Subcategory	Coal-fired unit designed for coal ≥ 8,300 Btu/lb	Coal-fired unit designed for coal < 8,300 Btu/lb	IGCC, lb/TBtu (lb/GWh)	Liquid oil, lb/TBtu (lb/GWh)	Solid oil-derived
Chromium, Cr	3.0 lb/TBtu (0.030 lb/GWh).	3.0 lb/TBtu (0.030 lb/GWh).	3.0 (0.020)	2.0 (0.020)	2.0 lb/TBtu (0.020 lb/GWh).
Cobalt, Co	0.80 lb/TBtu (0.0080 lb/GWh).	0.80 lb/TBtu (0.0080 lb/GWh).	2.0 (0.0040)	3.0 (0.020)	2.0 lb/TBtu (0.020 lb/GWh).
Lead, Pb	2.0 lb/TBtu (0.020 lb/GWh).	2.0 lb/TBtu (0.020 lb/GWh).	0.0002 lb/MMBtu (0.003 lb/MWh).	2.0 (0.030)	11.0 lb/TBtu (0.020 lb/GWh).
Manganese, Mn	5.0 lb/TBtu (0.050 lb/GWh.	5.0 lb/TBtu (0.050 lb/GWh.	3.0 (0.020)	5.0 (0.060)	3.0 lb/TBtu (0.040 lb/GWh).
Mercury, Hg	NA	NA	NA	0.050 lb/TBtu (0.00070 lb/GWh).	NA.
Nickel, Ni	4.0 lb/TBtu (0.040 lb/GWh).	4.0 lb/TBtu (0.040 lb/GWh).	5.0 (0.050)	8.0 (0.080)	9.0 lb/TBtu (0.090 lb/GWh).
Selenium, Se	6.0 lb/TBtu (0.060 lb/GWh).	6.0 lb/TBtu (0.060 lb/GWh).	22.0 (0.20)	2.0 (0.020)	2.0 lb/TBtu (0.020 lb/GWh).

NA = Not applicable.

TABLE 16—ALTERNATE EMISSION LIMITATIONS FOR NEW COAL- AND OIL-FIRED EGUS

Subcategory	Coal-fired unit designed for coal ≥ 8,300 Btu/lb	Coal-fired unit designed for coal < 8,300 Btu/lb	IGCC *	Liquid oil, lb/GWh	Solid oil-derived
SO_2	0.40 lb/MWh	0.40 lb/MWh	0.40 lb/MWh	NA	0.40 lb/MWh.
Total metals	0.000040 lb/MWh	0.000040 lb/MWh	0.000040 lb/MWh	NA	0.00020 lb/MWh.
Antimony, Sb	0.000080 lb/GWh	0.000080 lb/GWh	0.000080 lb/GWh	0.0020	0.00090 lb/GWh.
Arsenic, As	0.00020 lb/GWh	0.00020 lb/GWh	0.00020 lb/GWh	0.0020	0.0020 lb/GWh.
Beryllium, Be	0.000030 lb/GWh	0.000030 lb/GWh	0.000030 lb/GWh	0.00070	0.000080 lb/GWh.
Cadmium, Cd	0.00040 lb/GWh	0.00040 lb/GWh	0.00040 lb/GWh	0.00040	0.0070 lb/GWh.
Chromium, Cr	0.020 lb/GWh	0.020 lb/GWh	0.020 lb/GWh	0.020	0.0060 lb/GWh.
Cobalt, Co	0.00080 lb/GWh	0.00080 lb/GWh	0.00080 lb/GWh	0.0060	0.0020 lb/GWh.
Lead, Pb	0.00090 lb/GWh	0.00090 lb/GWh	0.00090 lb/GWh	0.0060	0.020 lb/GWh.
Mercury, Hg	NA	NA	NA	0.00010 lb/GWh	NA.
Manganese, Mn	0.0040 lb/GWh	0.0040 lb/GWh	0.0040 lb/GWh	0.030	0.0070 lb/GWh.
Nickel, Ni	0.0040 lb/GWh	0.0040 lb/GWh	0.0040 lb/GWh	0.040	0.0070 lb/GWh.
Selenium, Se	0.030 lb/GWh	0.030 lb/GWh	0.030 lb/GWh	0.0040	0.00090 lb/GWh.

* Beyond-the-floor as discussed elsewhere.
NA = Not applicable.

Most, if not all, coal-fired EGUs and solid oil-derived fuel-fired EGUs already have emission limitations for SO_2 under either the Federal NSPS, individual SIP programs, or the Federal ARP and, as a result, have SO_2 emission controls installed. Further, again most, if not all, coal-fired EGUs have SO_2 CEMS installed and operating under the provisions of one of these programs. Thus, as SO_2 is a suitable surrogate for the acid gas HAP, it could be used as an alternate equivalent standard to the HCl standard for EGUs with FGD systems installed and operated at normal capacity. An SO_2 standard would ensure that equivalent control of the acid gas HAP is achieved, and some facilities may find it preferable to use the existing SO_2 CEMS for compliance purposes rather than having to perform the manual HCl compliance testing. As noted elsewhere, this approach does not work for EGUs that do not have SO_2 controls installed and, thus, those EGUs may not utilize the alternate SO_2 limitations. Further, no SO_2 data were provided by the two IGCC units; therefore, there is no alternative SO_2 limitation being proposed for existing IGCC units.

Some sources have expressed a preference for individual non-Hg metal HAP emission limitations rather than the use of PM as a surrogate. Thus, EPA has analyzed the data for that purpose and we are proposing both alternate individual HAP metal limitations and total HAP metal limitations for all subcategories except liquid oil-fired EGUs. These limitations provide equivalent control of metal HAP as the proposed PM limitations.

We are soliciting comments on all aspects of these alternate emission limitations.

VI. Background Information on the Proposed NSPS

A. What is the statutory authority for this proposed NSPS?

New source performance standards implement CAA section 111(b), and are issued for source categories which EPA has determined cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. CAA section 111(b)(1)(B) requires the EPA to periodically review and, if appropriate, revise the NSPS to reflect improvements in emissions reduction methods.

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

The current standards for steam generating units are contained in the NSPS for electric utility steam generating units (40 CFR part 60, subpart Da), industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db), and small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc). Previous standards that continue to apply to owners/operators of existing affected facilities, but which have been superseded for owner/operators of new affected facilities, are contained in the NSPS for fossil-fuel-fired steam generating units for which construction was commenced after August 17, 1971, but on or before September 18, 1978 (40 CFR part 60, subpart D).

B. Summary of State of New York, et al., v. EPA Remand

On February 27, 2006, EPA promulgated amendments to the NSPS for EGUs (40 CFR part 60, subpart Da) which established new standards for PM, SO_2, and NO_X (71 FR 9,866). EPA was subsequently sued on the amendments by multiple state governments, municipal governments, and environmental organizations (collectively the Petitioners). *State of New York* v. *EPA,* No. 06–1148 (DC Cir.). The Petitioners alleged that EPA failed to correctly identify the best system of emission reductions for the newly established SO_2 and NO_X standards. The Petitioners also contended that EPA was required to establish separate emission limits for fine filterable PM ($PM_{2.5}$) and condensable PM. Finally, the petitioners claimed the NSPS failed to reflect the degree of emission limitation achievable through the application of IGCC technology. Based upon further examination of the record, EPA determined that certain issues in the rule warranted further consideration. On that basis, EPA sought and, on September 4, 2009, was granted a voluntary remand without vacatur of the 2006 amendments.

C. EPA's Response to the Remand

The emission standards established by the 2006 final rule, which are more stringent than the standards in effect prior to the adoption of the amendments, remain in effect and will continue to apply to affected facilities for which construction was commenced after February 28, 2005, but before May 4, 2011. Following careful consideration of all of the relevant factors, EPA is proposing to establish amended standards for PM, SO_2, and NO_X which would apply to owners/operators of affected facilities constructed, reconstructed, or modified after May 3, 2011.

In terms of the timing of our response to the remand, we consider it appropriate to propose revisions to the NSPS in conjunction with proposing the EGU NESHAP. There are some commonalities among the controls needed to comply with the requirements of the two rules and syncing the two rules so that they apply to the same set of new sources will allow owners/operators of those sources to better plan to comply with both sets of requirements. Therefore, we are proposing these revisions in conjunction with proposing the NESHAP, and intend to finalize both rules simultaneously.

As explained in more detail below and in the technical support documents, we have concluded that the proposed PM, SO_2, and NO_X standards set forth in this proposed rule reflect BDT. In addition, we have concluded that the most appropriate approach to reduce emissions of both filterable $PM_{2.5}$ and condensable PM is to establish a total PM standard, rather than establishing separate standards for each form of PM.The total PM standard, total filterable PM plus condensable PM, set forth in this proposed rule reflects BDT for all forms of PM. We have concluded that establishing a single total PM standard is preferable for a number of reasons. First, this approach effectively accounts for and requires control of both primary forms of PM, filterable PM, which includes both filterable PM_{10} (PM in the stack with an aerodynamic diameter less than or equal to a nominal 10 micrometers) and filterable $PM_{2.5}$ (PM in the stack with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers) and condensable PM (materials that are vapors or gases at stack conditions but form solids or liquids upon release to the atmosphere). Second, we have concluded that the same control device constitutes BDT for both forms of filterable PM. Best demonstrated technology for control of both filterable PM_{10} and filterable $PM_{2.5}$ emissions from steam generating units is based upon the use of a FF with coated or membrane filter media bags. Fabric filters control the fine particulate sizes that compose filterable $PM_{2.5}$ and the coarser particulate sizes that are a component of filterable PM_{10} through the same means. Since a FF controls total filterable PM and cannot selectively control filterable $PM_{2.5}$, establishing separate filterable $PM_{2.5}$ and filterable PM_{10} standards would not result in any further reduction in emissions. Thus, although the NSPS for steam generating units do not establish individual standards for filterable PM_{10} and $PM_{2.5}$, the NSPS PM standards for steam generating units do result in control of both of these filterable PM size categories based on the use of the control technologies identified as BDT and used to derive the proposed PM standards. Third, size fractionation of the PM in stacks with entrained water droplets (i.e., those downstream of a wet FGD scrubber) is challenging since the water droplets contain suspended and dissolved material which would form particulate after exiting the stack when the water droplet is evaporated. This challenge is exacerbated due to the difficulties of collecting the water droplets and quickly evaporating the water to reconstitute the suspended and dissolved materials in their eventual final size without changing their size as a result of shattering, agglomeration and deposition on the sample equipment. Although the Agency and others are working toward technologies that may allow particle sizing in wet stack conditions, there is currently no viable test method to determine the size fraction of the filterable PM for stacks that contain water droplets. Because many new EGUs are expected to use wet scrubbers and/or a WESP, owners/operators of these units would have no method to determine compliance with a fine filterable PM standard.

Under the existing NSPS, BDT for an owner/operator of a new affected facility is a FF for control of filterable PM and an FGD for control of SO_2. Depending on the specific stack conditions and coal type being burned, fabric filters may also provide some co-benefit reduction in condensable PM emissions. Furthermore, an FGD designed for SO_2 control has the co-benefit of reducing, to some extent, condensable PM emissions. Therefore, the existing NSPS baseline for control of condensable PM is a FF in combination with an FGD. We have concluded that the additional use of a WESP system in combination with DSI is BDT for condensable PM. We have concluded that it is appropriate to regulate both filterable and condensable PM under a single standard since they may be impacted differently by common controls. For example, DSI is one of the approaches that could be used to reduce the sulfuric acid mist (SO_3 and H_2SO_4) portion of the condensable PM. However, addition of sorbent adds filterable PM to the system and could conceivably increase filterable PM emissions. When using a wet FGD, some small amount of scrubber solids (gypsum, limestone) can be entrained into the exiting gas, resulting in an increase in filterable PM emissions. In each of these cases, technologies used to meet a stringent separate condensable PM standard could result in an increase in filterable PM emissions, a portion of which consist of fine filterable PM. This increase in filterable PM may challenge the ability of the owner/operator of the affected facility to meet a similarly stringent filterable PM standard. Filterable and condensable PM are often controlled using separate or complimentary technologies—though there are technologies, (*e.g.,* WESP), that can control both filterable and condensable PM emissions. Often times the equipment is used to also control other pollutants such as SO_2, HCl, and Hg. A combined PM standard allows for optimal design and operation of the control equipment. Thus, with the data available to us it is unclear what system of emissions reduction would result in the best overall environmental performance if we attempted to established separate filterable and condensable PM standards and what an appropriate condensable PM standard would be. At this time, the use of a total PM standard is the most effective indicator that the emissions standard is providing the best control of both filterable and condensable $PM_{2.5}$ emissions as well as coarse filterable PM emissions. We are requesting comment on whether separate filterable $PM_{2.5}$ and condensable PM standards would be appropriate and what the numerical values of any such standards should be.

EPA disagrees with the petitioners claim that the NSPS should be based on the performance of IGCC units. The NSPS is a national standard and IGCC is not appropriate in every situation. Although IGCC units have many advantages, technology choice is based on several factors, including the goals and objectives of the owner or operator constructing a facility, the intended purpose or function of the facility, and the characteristic of the particular site. In addition, the emissions benefits resulting from reduced emissions of criteria pollutants are not sufficient in all instances to justify the higher capital costs of today's IGCC units if IGCC is selected as BDT in establishing a national standard. The emissions benefits may, however, be sufficient to justify the use of IGCC in an individual case, after considering cost and other relevant factors, including those described above.

D. EPA's Response to the Utility Air Regulatory Group's Petition for Reconsideration

On January 28, 2009, EPA promulgated amendments separate from the above mentioned amendments to the NSPS for EGUs (40 CFR part 60, subpart Da, 74 FR 5,072). The Utility Air Regulatory Group (UARG) subsequently requested reconsideration of that rulemaking and EPA granted that reconsideration. Specific issues raised by UARG included the opacity monitoring requirements for owners/operators of affected facilities subject to an opacity standard that are not required to install a continuous opacity monitoring system (COMS). Another issue raised by UARG was the opacity standard for owners/operators of affected facilities subject to 40 CFR part 60, subpart D. We are requesting comments on both of these issues in this rulemaking.

VII. Summary of the Significant Proposed NSPS Amendments

The proposed amendments would amend the emission limits for PM, SO_2, and NO_X from steam generating units in 40 CFR part 60, subpart Da. Only those facilities that begin construction, modification, or reconstruction after May 3, 2011 would be affected by the proposed amendments. In addition to proposing to amend the identified emission limits, we are also proposing several less significant amendments, technical clarifications, and corrections to various provisions of the existing utility and industrial steam generating unit NSPS, as explained below.

A. What are the proposed amended emissions standards for EGUs?

We are proposing to amend the PM, SO_2, and NO_X standards for owners/operators of new, modified, and reconstructed units on which construction is commenced after May 3, 2011 as follows. We are proposing a total PM emissions standard (filterable plus condensable PM) for owners/operators of new and reconstructed EGUs of 7.0 nanograms per joule (ng/J) (0.055 lb/MWh) gross energy output. The proposed PM standard for modified units is 15 ng/J (0.034 lb/MMBtu) heat input.

We are proposing an SO_2 emissions standard for new and reconstructed EGUs of 130 ng/J (1.0 lb/MWh) gross energy output or a 97 percent reduction of potential emissions regardless of the type of fuel burned with the following exception. We are not proposing to amend the SO_2 emissions standard for EGUs that burn over 75 percent coal refuse. We are also not proposing to amend the SO_2 emission standard for owners/operators of modified EGUs because of the incremental cost effectiveness and potential site specific limited water availability. Without access to adequate water supplies owners/operators of existing facilities would not be able to operate a wet FGD.

We are co-proposing two options for an amended NO_X emissions standard. EPA's preferred approach would establish a combined NO_X plus CO standard for owners/operators of new, reconstructed, and modified units. The proposed combined standard for new and reconstructed EGUs is 150 ng/J (1.2 (lb NO_X + lb CO)/MWh) and the proposed combined standard for modified units is 230 ng/J (1.8 (lb NO_X + lb CO)/MWh). EPA prefers the approach of establishing a combined standard because it provides additional compliance flexibility while still providing an equivalent or superior level of environmental protection. Alternatively, we are proposing to amend the NO_X emission standard for new, modified, and reconstructed EGUs to 88 ng/J (0.70 lb/MWh) gross energy output regardless of the type of fuel burned and not establish any CO standards.

In addition to proposing revised emission standards, we are also proposing to amend the way an owner/operator of an affected facility would calculate compliance with the proposed standards. Under the existing NSPS, averages are calculated as the arithmetic average of the non out-of-control hourly emissions rates (*i.e.,* hours during which the monitoring device has not failed a quality assurance or quality control test) during the applicable averaging period. For the revised standards, we are proposing that the average be calculated as the sum of the applicable emissions divided by the sum of the gross output of non out-of-control hours during the averaging period. We are proposing this change in part to facilitate moving from the existing PM, SO_2, and NO_X standards, which exclude periods of startup and shutdown, to the proposed PM, SO_2, and NO_X standards, which would include periods of startup and shutdown.

B. Would owners/operators of any EGUs be exempt from the proposed amendments?

We are proposing several amendments that would exempt owners/operators from certain of the proposed amendments. First, we are proposing that owners/operators of innovative emerging technologies that apply for and are granted a commercial demonstration permit by the Administrator for an affected facility that uses a pressurized fluidized bed, a multi-pollutant emissions control system, or advanced combustion controls be exempt from the proposed amended standard. Owners/operators of these technologies would instead demonstrate compliance with standards similar to those finalized in the 2006 amendments. The total PM standard would be 0.034 lb/MMBtu heat input, the SO_2 standard would be 1.4 lb/MWh gross output or a 95 percent reduction in potential emissions, and the NO_X standard would be 1.0 lb/MWh gross output. In the event we finalize a combined NO_X/CO standard, the corresponding combined limit would be 1.4 lb/MWh gross output. In addition, we are proposing to harmonize all of the steam generating unit NSPS by exempting all steam generating units combusting natural gas and/or low sulfur oil from PM standards and exempting all steam generating units burning natural gas from opacity standards. Finally, we are proposing to exempt owners/operators of affected facilities subject to 40 CFR part 60, subpart Eb (standards of performance for large MWCs), from 40 CFR part 60, subpart Da, exempt owners/operators of affected facilities subject to 40 CFR part 60, subpart CCCC (standards of performance for commercial and industrial solid waste incineration), units from 40 CFR part 60, subparts Da, Db, and Dc, exempt owners/operators of affected facilities subject to 40 CFR part 60, subpart BB (standards of performance for Kraft pulp mills), from the PM standards under 40 CFR part 60, subpart Db, and exempt owners/operators of fuel gas combustion devices subject to 40 CFR part 60, subpart Ja (standards of performance for petroleum refineries), from the SO_2 standard under 40 CFR part 60, subpart Db.

C. What other significant amendments are being proposed?

A complete list of the corrections and technical amendments and corrections is available in the docket in the form of a redline/strikeout version of the existing regulatory language. These additional amendments are being proposed to clarify the intent of the current requirements, correct inaccuracies, and correct oversights in previous versions that were promulgated. The additional significant amendments are as follows.

We are proposing several definitional changes. First, to provide additional flexibility and recognize the environmental benefit of efficient production of electricity we are proposing to expand the definition of the affected facility under 40 CFR part 60, subpart Da, to include integrated CTs and fuel cells. Second, because petroleum coke is increasingly being burned in EGUs selling over 25 MW of electric output, we are proposing to amend the definition of petroleum to include petroleum coke. Next, to minimize permitting and compliance burdens and avoid situations where an IGCC facility switches between different NSPS (40 CFR part 60, subparts KKKK and Da), we are proposing to amend the definition of an IGCC facility to allow the Administrator to exempt owners/operators from the 50 percent solid-derived fuel requirement during construction and repair of the gasifier. Owners/operators of IGCC units might install and operate the stationary CT prior to completion of the gasification system. Under the existing standards, an owner/operator doing this would first be subject to 40 CFR part 60, subpart KKKK, and applicability would switch once the gasification system is completed. This outcome would not result in any additional reduction in emissions. The proposed change would thus reduce regulatory burden without decreasing environmental protection. Finally, both biodiesel and kerosene have combustion characteristics similar to those of distillate oil. Therefore, we are proposing to expand the definition of distillate oil in 40 CFR part 60, subparts Db and Dc, to include both biodiesel and kerosene such that units burning any of these fuels, either separately or in combination would be subject to the same requirements.

Additional proposed amendments include deleting vacated provisions and additional harmonization across the various steam generating unit NSPS. As explained above, CAMR was vacated by the DC Circuit Court in 2008. As a result, the provisions added to 40 CFR part 60, subpart Da, by CAMR are no longer enforceable. Therefore, we are proposing to delete the provisions in 40 CFR part 60, subpart Da, that reference Hg standards and Hg testing and monitoring provisions. In addition, existing 40 CFR part 60, subpart HHHH (Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units), which was promulgated as part of CAMR, and was, therefore, also vacated by the court's decision, will be removed and that subpart will be deleted. We are proposing to harmonize all of the steam generating unit NSPS by adding BLDS and ESP parameter monitoring systems as alternatives to the requirement to install a COMS in all the subparts (40 CFR part 60, subparts D, Da, Db, and Dc). We are also proposing to change the date by which owners/operators of affected facilities subject to all of the steam generating unit NSPS are to begin submitting performance test data electronically from July 1, 2011, to January 1, 2012.

VIII. Rationale for This Proposed NSPS

The proposed new emission standards for EGUs would apply only to affected sources that begin construction, modification, or reconstruction after May 3, 2011. Based on our review of emission data and control technology information applicable to criteria pollutants, we have concluded that amendments of the PM, SO_2, and NO_X emission standards are appropriate. The technical support documents that accompany the proposal describe in further detail how the proposed amendments to the NSPS reflect the application of the BDT for these sources considering the performance and cost of the emission control technologies and other environmental, health, and energy factors. In establishing the proposed revised emission limits based on BDT, we have to the extent that it is practical and reasonable to do so adopted a fuel and technology neutral approach and have expressed the proposed emission limits on an output basis. These approaches provide the level of emission limitation required by the CAA for the NSPS program while at the same time achieving the additional benefits of compliance flexibility, increased efficiency, and the use of cleaner fuels.

The fuel and technology neutral approach provides a single emission limit for steam generating units based on the application of BDT without regard to the specific type of steam generating equipment or fuel being used. We have concluded that this approach provides owners/operators of affected facilities an incentive to carefully consider fuel use, boiler type, and control technology in planning for new units so as to use the most effective combination of add-on control technologies, clean fuels, and boiler design based on the circumstances to meet the emission standards.

To develop a fuel- and technology-neutral emission limit, we first analyzed data on emission control performance from coal-fired units to establish an emission level that represents BDT for units burning coal. We adopted this approach because the higher sulfur, nitrogen, and ash contents for coal compared to oil or gas makes application of BDT to coal-fired units more complex than application of BDT to either oil- or gas-fired units. Because of these complexities, emission levels selected for coal-fired steam generating units using BDT would also be achievable by oil- and gas-fired EGUs. Thus, we are proposing that the emission levels established through the application of BDT to coal-fired units apply to all boiler types and fuel use combinations. We have concluded that this fuel-neutral approach both satisfies the requirements of CAA section 111(b) and provides a clear incentive to use cleaner fuels where it is possible to do so.

Where feasible, we are proposing output-based (gross basis) standards in furtherance of pollution prevention which has long been one of our highest priorities. In the current context, maximizing the efficiency of energy generation represents a key opportunity to further pollution prevention. An output-based format establishes emission standards that encourage unit efficiency by relating emissions to the amount of useful-energy generated, not the amount of fuel burned. By relating emission limitations to the productive output of the process, output-based emission standards encourage energy efficiency because any increase in overall energy efficiency results in a lower emissions rate. Output-based standards provide owners/operators of regulated sources with an additional compliance option (*i.e.,* increased efficiency in producing useful output) that can result in both reduced compliance costs and lower emissions. The use of more efficient generating technologies reduces fossil fuel use and leads to multi-media reductions in environmental impacts both on-site and off-site. On-site benefits include lower emissions of all products of combustion, including HAP, as well as reducing any solid waste and wastewater discharges. Off-site benefits include the reduction of emissions and non-air environmental impacts arising from the production, processing, and transportation of fuels and the disposal of by-products of combustion such as fly-ash and bottom-ash.

The general provisions in 40 CFR part 60 provide that "emissions in excess of the level of the applicable emissions limit during periods of startup, shutdown, and malfunction (shall not be) considered a violation of the applicable emission limit unless otherwise specified in the applicable standard." 40 CFR 60.8(c). EPA is proposing standards in this rule that apply at all times, including during periods of startup or shutdown, and periods of malfunction. In proposing the standards in this rule, EPA has taken into account startup and shutdown periods and, for the reasons explained below, has not proposed different standards for those periods.

To establish the proposed output-based SO_2 and NO_X standards, we used hourly pollutant emissions data and gross output data as reported to the Clean Air Markets Division (CAMD) of EPA. In general, retrofit existing units can perform as well as recently operational units. To establish a robust data set on which to base the proposed amendments, we analyzed emissions data from both older plants that have been retrofitted with controls and recently operational units. We did not attempt to filter out periods of startup or shutdown and the proposed standards, therefore, account for those periods.

If any persons believe that our conclusion is incorrect, or that we have failed to consider any relevant information on this point, we encourage them to submit comments. In particular, we note that the general provisions in 40 CFR part 60 require facilities to keep records of the occurrence and duration of any startup, shutdown or malfunction (40 CFR 60.7(b)) and either report to EPA any period of excess emissions that occurs during periods of startup, shutdown, or malfunction (40 CFR 60.7(c)(2)) or report that no excess emissions occurred (40 CFR 60.7(c)(4)). Thus, any comments that contend that sources cannot meet the proposed standard during startup and shutdown periods should provide data and other specifics supporting their claim.

In developing the proposed 30-day SO_2 and NO_X standards, we summed the unadjusted emissions for all non-out-of-control operating hours and divided that value by the sum of the gross electrical energy output over the same period. For the purposes of this analysis, out-of-control hours were defined as when either the unadjusted applicable emissions or gross output could not be determined for that operating hour. The reduction in potential SO_2 emissions was calculated by comparing the reported SO_2 emissions during a 30-day period to the potential emissions for that same 30-day period. Potential uncontrolled SO_2 emissions were calculated using monthly delivered fuel receipts and fuel quality data from the EIA forms EIA–923, EIA–423, and FERC–423, as applicable. For each operating day, the total potential uncontrolled SO_2 emissions were calculated by multiplying the uncontrolled SO_2 emissions rate for the applicable month as determined using the EIA data by the heat input for that day. This revised averaging approach gives more weight to high load hours and more accurately reflects overall environmental performance. In addition, because low load hours do not factor as heavily into the calculated average the impact of including periods of startup and shutdown is minimized.

Particulate matter and CO data are not reported to CAMD and instead were collected as part of the 2010 ICR. Total PM testing was reported as part of the 2010 ICR and those data were used in both rulemakings. As part of the 2010 ICR, owners/operators reported CO performance test data and whether or not they have a CO CEMS installed on their facility. We requested CO CEMS data from multiple units to compare the relationship between NO_X and CO. The 30-day combined NO_X/CO standard was calculated using the same approach as for NO_X and SO_2.

A. How are periods of malfunction addressed?

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 60.2.) EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 111 standards. Further, nothing in CAA section 111 or in case law requires that EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. *See, Weyerhaeuser* v *Costle,* 590 F.2d 1011, 1058 (DC Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.")

Further, it is reasonable to interpret CAA section 111 as not requiring EPA to account for malfunctions in setting emissions standards. For example, we note that section 111 provides that EPA set standards of performance which reflect the degree of emission limitation achievable through "the application of the best system of emission reduction" that EPA determines is adequately demonstrated. Applying the concept of "the application of the best system of emission reduction" to periods during which a source is malfunctioning presents difficulties. The "application of the best system of emission reduction" is more appropriately understood to include operating units in such a way as to avoid malfunctions.

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 111 standards for EGUs under 40 CFR part 60, subpart Da. As noted above, by definition, malfunctions are sudden and unexpected events and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in the category. Moreover, malfunctions can vary in frequency, degree, and duration, further complicating standard setting.

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." 40 CFR 60.2 (definition of malfunction).

Finally, EPA recognizes that even equipment that is properly designed and maintained can sometimes fail. Such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.,* State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (September 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (February 15, 1983)). EPA is, therefore, proposing to add an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. *See* 40 CFR 60.41Da (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also are proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 60.46Da. (*See* 40 CFR 22.24). These criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 60.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *" The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 60.40Da and to prevent future malfunctions. For example, the source would have to prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *" and that "[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *" In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met the burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113 (see also 40 CFR part 22.77).

B. How did EPA determine the proposed emission limitations?

1. Selection of the Proposed PM Standard

Controls for filterable PM are well established. Either an ESP or FF can control both coarse and fine filterable PM. However, controls for condensable PM are less developed. Condensable PM from a coal-fired boiler is composed primarily of SO_3 and H_2SO_4 but may also contain smaller amounts of nitrates, halides, ammonium salts, and volatile metals such as compounds of Hg and Se. Controls that are expected to reduce emissions of condensable PM include the use of lower sulfur coals, the use of an SCR catalyst or other NO_X control device with minimal SO_2 to SO_3 conversion, use of an FGD scrubber, injection of an alkaline sorbent upstream of a PM control device, and use of a WESP. Other control technologies such as FFs or ESPs may also provide some reduction in condensable PM—depending on the flue gas temperature and the composition of the fly ash and other bulk PM. It is unlikely that owners/operators of modified units could universally further reduce the condensable fraction of the PM as they already have FGD controls, operating the PM control at a cooler temperature (or relocating to a cooler location) are not practical options due to concerns with corrosion, and it is possible that the existing ductwork might not make DSI viable without significant adjustments. Therefore, we have concluded that BDT for modified units should be based on the use of a FF in combination with an FGD. Based on the 2010 ICR data for total PM, there are performance tests for 63 units below the existing NSPS filterable PM standard (0.015 lb/MMBtu), that have some type of SO_2 control, and that use a FF. Ninety four percent of these performance tests are achieving an emissions rate of 0.034 lb/MMBtu for total PM, and we have concluded that this value is an achievable standard for owners/operators of modified units. It is also approximately equivalent in stringency to the existing filterable PM standard because no specific condensable PM controls would necessarily be required. However, we have concluded that new EGUs will factor in condensable PM controls. BDT for new EGUs would be a FF and FGD in combination with both DSI and a WESP. Based on the 2010 ICR data for total PM, there are performance tests for 48 units below the existing NSPS filterable PM standard (0.015 lb/MMBtu), that have some type of SO_2 control, that use a FF, and that reported gross electrical output during the performance test. Because no owners/operators of EGUs are presently specifically attempting to control condensable PM beyond eliminating the visible blue plume that can occur from sulfuric acid mist emissions, we concluded it was appropriate to use the top 20 percentile of the performance test data for the proposed total PM standard. The top 20 percentile of these performance tests is 7.0 ng/J (0.055 lb/MWh). We are soliciting comments on the proposed standard and are considering the range of 15 ng/J (0.034 lb/MMBtu) to 5.0 ng/J (0.040 lb/MWh) for the final rule. We are also requesting comment on whether an input-based standard is more appropriate for standards where compliance is based on performance tests instead of CEMS.

2. How did EPA select the proposed SO_2 standard?

A number of SO_2 control technologies are currently available for use with new coal-fired EGUs. Owners/operators of new steam generating projects that use IGCC technology can remove the sulfur associated with the coal in downstream processes after the coal has been gasified. Owner/operators of new steam generating units that use FBC technology can control SO_2 during the combustion process by adding limestone into the fluidized-bed, and, if necessary, installing additional post-combustion controls. Owners/operators of steam generating units using PC combustion technology can use post-combustion controls to remove SO_2 from the flue gases. Additional control strategies that apply to all steam generating units include the use of low sulfur coals, coal preparation to improve the coal quality and lower the sulfur content, and fuel blending with inherently low sulfur fuels.

To assess the SO_2 control performance level of EGUs, we reviewed new and retrofitted units with SO_2 controls. Table 17 of this preamble shows the performance of several of the best performing units in terms of percent reduction in potential SO_2 emissions identified in our analysis of coal-fired EGUs.

TABLE 17—SO_2 EMISSIONS PERFORMANCE DATA

Facility	Time period	Maximum 30-day SO_2 emissions rate (lb/MWh)	Minimum 30-day percent SO_2 reduction
Cayuga 1	12/08–12/09	1.03	97.4
Harrison 1	01/06–01/09	1.45	96.7
Harrison 2	01/06–01/09	1.01	97.7
Harrison 3	01/06–01/09	0.97	98.2
HL Spurlock 1	06/09–12/09	1.83	96.9
HL Spurlock 2	11/08–12/09	1.26	98.0
HL Spurlock 3	01/09–12/09	1.45	96.5
HL Spurlock 4	01/09–12/09	1.08	97.7
Wansley 1	02/09–12/09	0.31	97.7
Wansley 2	05/09–12/09	0.37	97.4
Iatan 1	04/09–12/09	0.16	98.2
Jeffrey 2	05/09–12/09	0.09	99.0
Jeffrey 3	04/09–12/09	0.13	98.5
Trimble County 1	01/05–12/09	1.14	97.6
Mountaineer 1	05/07–12/09	1.15	97.6

With the exception of the HL Spurlock 3 and 4 units all of the listed units use wet limestone-based scrubbers. HL Spurlock 3 and 4 are FBC boilers that remove the majority of SO_2 using limestone injection into the boiler and then remove additional SO_2 by lime injection into the ductwork prior to the FF. Of the identified best performing units, we only have multiple years of performance data for the Harrison, Trimble County, and Mountaineer units. Based on the performance of these units, we have concluded that 97 percent reduction in potential SO_2 emissions has been demonstrated and is achievable on a long term basis. This level of reduction has also been demonstrated at each separate unit at each location in Table 17 of this preamble and accounts for variability in performance of individual scrubbers. Therefore, the proposed upper limit on a percent reduction basis is 97 percent. Even though the Iatan and Jeffrey units are achieving a 98 percent reduction in potential SO_2 emissions, we are not proposing this standard because it is based on relatively short-term data. Based on the variability in SO_2 reductions from the Harrison, Trimble County, and Mountaineer units, we have concluded that short-term data do not necessarily take into account the range of operating conditions that a facility would be expected to operate or control equipment variability and degradation. We are soliciting comments on the proposed limit and are considering the range of 96 to 98 percent reduction in potential SO_2 emissions for the final rule.

To determine an appropriate alternate numerical standard, we evaluated the performance of several recently constructed units in addition to the numerical standards for the units in Table 17 of this preamble. Table 18 of this preamble shows the maximum 30-day average SO_2 emissions rate of units that commenced operation between 2005 and 2008, that are emitting at levels below the current NSPS, and that reported both SO_2 emissions and gross electric output data to CAMD.

TABLE 18—SO_2 EMISSIONS PERFORMANCE DATA FOR NEW EGUS

Facility	SO_2 control technology	In service date	Maximum 30-day SO_2 emissions rate (lb/MWh)
Weston 4	Lime-based Spray Dryer	2008	0.61
Cross 4	Wet Limestone FGD	2008	1.02
TS Power Plant 1	Lime-based Spray Dryer	2008	0.56
Wygen II	Lime-based Spray Dryer	2008	0.95
Walter Scott Jr. Energy Center 4	Lime-based Spray Dryer	2007	0.73
Cross 3	Wet Limestone FGD	2007	1.06
Springerville TS3	Lime-based Spray Dryer	2006	1.04
HL Spurlock 3	Fluidized Bed Limestone Injection + Lime Injection	2005	1.45

The HL Spurlock 3 unit is the only new unit that burns high sulfur coal and that unit could meet the proposed alternate percent reduction standard. However, it would not be expected to achieve a numerical standard based on the performance of the other units. Further, with the exception of the Cross 3 and 4 units, which burn medium sulfur bituminous coals, the remaining units burn lower-sulfur subbituminous coals. To provide the maximum emissions reduction, we further concluded that the alternate numerical standard should be as stringent as the numerical rates achieved by the units used to determine the percent reduction standard. If the alternate numerical standard were less stringent than the emissions rate achieved by the units used to determine the maximum percent reduction, those units would not be required to achieve the maximum percent reduction that has been demonstrated. In addition, the numerical standard should account for variability in today's SO_2 control technologies and provide sufficient compliance margin for owners/operators of new units burning medium sulfur coals to comply with the numerical standard and thereby provide an incentive to burn cleaner fuels. The sulfur concentrations in the flue gas of EGUs burning medium and low sulfur coals is more diffuse than for EGUs burning high sulfur coals, and it has not been demonstrated that units burning these coals would be able to achieve 97 percent reduction of potential emissions on a continuous basis. We are proposing 1.0 lb/MWh as the alternate numerical standard because it provides a comparable level of performance to the 97 percent reduction requirement and satisfies criteria mentioned above. The numerical standard would require at least 80 percent reduction even from the lowest sulfur coals and would accommodate the use of traditional spray dryer scrubbers for owner/operators of new units burning coal with uncontrolled SO_2 emissions of up to approximately 1.6 lb/MMBtu.

Based on the performance of the spray dryer at the Springerville TS3 unit, the numerical standard would provide sufficient flexibility such that an owner/operator of an EGU could burn over 90 percent of the subbituminous coals presently being used in combination with a spray dryer. This technology choice provides owners/operators the flexibility to minimize water use and associated waste water discharge, as well as reducing additional CO_2 that is chemically created as part of the SO_2 control device. Even though there is not necessarily an overall greenhouse (GHG) reduction from using a lime-based instead of a limestone-based scrubber, lime production facilities have relatively concentrated CO_2 streams. Capture and storage of CO_2 at the lime manufacturing facility could potentially be easier since separation of the CO_2 would not be necessary, as is the case with an EGU exhaust gas. Owners/operators of new and reconstructed units burning coals with higher uncontrolled SO_2 emissions would either have to use IGCC with a downstream process to control sulfur prior to combustion, FBC, or a wet SO_2 scrubbing system to comply with the proposed standard. The proposed limit would allow the higher sulfur coals (uncontrolled emissions of greater than approximately 3 lb SO_2/MMBtu) to demonstrate compliance with the 97 percent reduction requirement as an alternate to the numerical limit. We are soliciting comments on the proposed limit and are considering the range of 100 to 150 ng/J (0.80 to 1.2 lb/MWh) for the final rule.

Coal refuse (also called waste coal) is a combustible material containing a significant amount of coal that is reclaimed from refuse piles remaining at the sites of past or abandoned coal mining operations. Coal refuse piles are an environmental concern because of acid seepage and leachate production, spontaneous combustion, and low soil fertility. Units that burn coal refuse provide multimedia environmental benefits by combining the production of energy with the removal of coal refuse piles and by reclaiming land for productive use. Consequently, because of the unique environmental benefits that coal refuse-fired EGUs provide, these units warrant special consideration so as to prevent the amended NSPS from discouraging the construction of future coal refuse-fired EGUs in the U.S.

Coal refuse from some piles has sulfur contents at such high levels that they present potential economic and technical difficulties in achieving the same SO_2 standard that we are proposing for higher quality coals. Therefore, so as not to preclude the development of these projects, we are proposing to maintain the existing SO_2 emissions standard for owners/operators of affected facilities combusting 75 percent or more coal refuse on an annual basis.

We are proposing to maintain the existing SO_2 standard for modified units to preserve the use of spray dryer FGD. Existing units might not have access to adequate water for wet FGD scrubbers and it is not generally cost effective to upgrade existing spray dryer FGD scrubbers to a wet FGD scrubber. In addition, the 90 percent sulfur reduction for modified units also allows existing modified FBCs to comply without the addition of post-combustion SO_2 controls. We have concluded that it is not generally cost effective to add additional post combustion SO_2 controls for modified fluidized beds.

3. Selection of the Proposed NO_X Standard

In the 2006 final NSPS amendments (71 FR 9866), EPA concluded that advanced combustion controls were BDT. However, upon further review we have concluded this was not appropriate. Although select existing PC EGUs burning subbituminous coals have been able to achieve annual NO_X emissions of less than 1.0 lb/MWh (*e.g.,* Rush Island, Newton), PC EGUs burning other coal types using only combustion controls have not demonstrated similar emission rates. Lignite-fired PC EGUs have only demonstrated an annual NO_X emissions rate of 1.7 lb/MWh (*e.g.,* Martin Lake) and the best bituminous fired PC EGUs using only combustion controls are slightly higher than 2.0 lb/MWh on an annual basis (*e.g.,* Jack McDonough, Brayton Point, AES Cayuga, Genoa). The variability in NO_X control technologies results in a maximum 30-day average emissions rate typically being ¼ to ⅓ higher than the annual average emissions rate. Therefore, it has not been demonstrated that owners/operators of PC EGUs burning any coal type using advanced combustion controls could comply with the existing NO_X standard.

After re-evaluating the performance, costs, and other environmental impacts of adding SCR in addition to combustion controls, we have concluded that combustion controls in combination with SCR represents BDT for continuous reduction of NO_X emissions from EGUs. Therefore, the regulatory baseline for NO_X emissions is defined to be combustion controls in combination with the installation of SCR controls on all new PC-fired units.

To assess the NO_X control performance level of EGUs, we reviewed new and retrofitted units with post combustion NO_X controls. Table 19 of this preamble shows the performance of several of the best performing units identified in our analysis of coal-fired EGUs.

TABLE 19—NO_X PERFORMANCE DATA

Facility	Time period	Maximum 30-day NO_X emissions rate (lb/MWh)	Boiler type & primary coal rank
Havana 9	01/05–12/09	0.70	PC, Sub.
Walter Scott Jr. 4	04/07–12/09	0.58	PC, Sub.
Mirant Morgantown 1	06/07–12/09	0.65	PC, Bit.
Mirant Morgantown 2	06/08–12/09	0.70	PC, Bit.
Roxboro 2	01/09–12/09	0.67	PC, Bit.
Cardinal 1	01/09–12/09	0.38	PC, Bit.
Cardinal 2	01/09–12/09	0.46	PC, Bit.
Cardinal 3	01/09–12/09	0.45	PC, Bit.
Muskingum River 5	01/08–12/09	0.60	PC, Bit.
John E Amos	06/09–12/09	0.62	PC, Bit.
Mitchell 1	01/09–12/09	0.59	PC, Bit.
Mitchell 2	01/09–12/09	0.54	PC, Bit.
Weston 4	07/08–12/09	0.48	PC, Sub.
H L Spurlock 4	05/09–12/09	0.67	CFB, Bit.
Wansley 1	02/09–12/09	0.67	PC, Bit.
Wansley 2	01/09–12/09	0.59	PC, Bit.
Nebraska City 2	05/09–12/09	0.60	PC, Sub.
TS Power 1	07/08–12/09	0.49	PC, Sub.

Note: PC = pulverized coal.
CFB = circulating fluidized bed.
Sub = subbituminous coal.
Bit = bituminous coal.

All of the units listed in Table 19 of this preamble have demonstrated 0.70 lb/MWh is achievable. Even though some units are achieving a lower emissions rate, the majority of units listed in Table 19 of this preamble have less than a year of operating data. Proposing a more stringent standard might not provide sufficient compliance margin to account for expected variability in the long term performance of NO_X controls. Although not all affected facilities using SCR are currently achieving an emissions rate of 0.70 lb/MWh, all major boiler designs have demonstrated combustion controls that are able to reduce NO_X emissions to levels where the addition of SCR (or design modifications and operating changes to existing SCR) would allow compliance with a NO_X emissions rate of 0.70 lb/MWh. We are therefore selecting 88 ng/J (0.70 lb/MWh) as the proposed NO_X standard for new, modified, and reconstructed units. The range of values we are currently considering for the final rule is 76 to 110 ng/J (0.60 to 0.90 lb/MWh).

Combustion optimization for overall environmental performance is a balance between boiler efficiency, NO_X emissions, and CO emissions. Although a well operated boiler using combustion controls can achieve a high efficiency and both low NO_X and CO emissions, the pollutant emissions rates are related. For example, NO_X reduction techniques that rely on delayed combustion and lower combustion temperatures tend to increase incomplete combustion and result in a corresponding increase in CO emissions. Conversely, high levels of excess air can be used to control CO emissions. However, high levels of excess air increase NO_X emissions.

The proposed BDT for NO_X is combustion controls plus the application of SCR. However, there are several approaches an owner/operator could use to comply with an individual NO_X standard. One approach would be to use combustion controls to minimize the formation of NO_X to the maximum extent possible and then use a less efficient SCR systems. This tends to result in high CO emissions and significant unburned carbon in the fly ash. From an environmental perspective, we would prefer that owners/operators select combustion controls that result in slightly higher NO_X emissions without substantially increasing CO emissions, and use regular efficiency SCR systems. As compared to establishing individual pollutant emission standards, a combined NO_X plus CO standard accounts for variability in combustion properties and provides additional compliance strategy options for the regulated community, while still providing an equivalent level of environmental protection. In addition, a combined standard provides additional flexibility for owners/operators to minimize carbon and/or ammonia in the fly ash such that the fly ash could still be used in beneficial reuse projects.

In addition, an overly stringent NO_X standard has the potential to impede the ability of an owner/operator of an EGU from operating at peak efficiency thereby minimizing GHG emissions. A combined standard on the other hand allows owners/operators additional flexibility to operate at or near peak efficiency. A combined standard would also allow the regulated community to work with the local environmental permitting agency to minimize the pollutant of most concern for that specific area. We have previously established a combined NO_X plus CO combined emissions standard for thermal dryers at coal preparation plants (40 CFR part 60, subpart Y).

To assess the combined NO_X/CO performance level of EGUs, we requested data from units identified by the 2010 ICR as using certified CO CEMS and achieving the existing NSPS NO_X standard of 1.0 lb/MWh gross output. We continue to be interested in additional NO_X and CO certified CEMS data from EGUs and comparable units using that are achieving the existing NSPS NO_X standard of 1.0 lb/MWh gross output. Table 20 of this preamble shows the performance of the units identified in our analysis.

Table 20—NO$_X$/CO Performance Data

Facility	Time period	Maximum 30-day NO$_X$ + CO emissions rate (lb/MWh)	Maximum 30-day NO$_X$/CO emissions rate (lb/MWh)	Boiler type & primary coal rank
Northside 1	01/05–12/09	1.1	0.89/0.29	CFB, PC.
Northside 2	01/05–12/09	1.1	0.93/0.46	CFB, PC.
Walter Scott, Jr. 4	04/07–12/09	0.95	0.58/0.42	PC, Sub.
WA Parish 5	09/05–12/09	1.1	0.66/0.62	PC, Sub.
WA Parish 6	06/05–12/09	1.2	0.76/0.81	PC, Sub.
WA Parish 7	06/05–12/09	1.8	0.53/1.4	PC, Sub.
WA Parish 8	04/06–12/09	1.5	0.42/1.1	PC, Sub.
HL Spurlock 3	01/09–12/09	1.4	0.83/0.61	CFB, Bit.
HL Spurlock 4	05/09–12/09	1.4	0.67/0.70	CFB, Bit.
TS Power 1	04/08–12/09	0.80	0.49/0.47	PC, Sub.

Note: PC = pulverized coal or petroleum coke.
CFB = circulating fluidized bed.
Sub = subbituminous coal.

Because CO has not historically been a primary pollutant of concern for owners/operators of EGUs, it has not necessarily been a significant factor when selecting combustion control strategies and has not typically been continuously monitored. Due to the limited availability of CO CEMS data and to account for potential variability we are not aware of, we have concluded it is appropriate in this case to propose a standard with sufficient compliance margin to not inhibit the ability of owner/operators of EGUs to comply with NO$_X$ specific best available control technology (BACT) requirements or requirements that result from compliance with EPA's proposed Transport Rule. Although 2 of the units shown in Table 21 of this preamble are operating below 1.0 lb/MWh, there are 4 that are operating in the 1.1 to 1.2 lb/MWh range. To provide a compliance margin and to account for situations where NO$_X$ might be more of a priority pollutant than CO, we are proposing a combined standard of 1.2 lb/MWh. This margin is apparent when comparing the HL Spurlock and Northside units. These fluidized bed boilers use selective non-catalytic reduction (SNCR) to reduce NO$_X$ emissions. Although the HL Spurlock units perform better in terms of NO$_X$, the combustion controls result in higher CO and combined NO$_X$/CO emission rates. In determining the appropriate combined standard for owner/operators of modified units, we used the data from the WA Parish units. All four of these units have been retrofitted to comply with stringent NO$_X$ requirements. Owners/operators of modified units could potentially have a more difficult time controlling both NO$_X$ and CO because the configuration of the boiler cannot be changed. All 4 of the WA Parish units have demonstrated that a standard of 230 ng/J (1.8 lb/MWh) is achievable and we are, therefore, proposing that standard for modified units. We are requesting comment on these standards and are considering a range of 130 to 180 ng/J (1.0 to 1.4 lb/MWh) for new and reconstructed units and of 180 to 230 ng/J (1.4 to 1.8 lb/MWh) for modified units.

Another potential GHG benefit, beyond boiler efficiency, of a combined NO$_X$ + CO standard is the flexibility to minimize nitrous oxide (N_2O) emissions. Formation of N_2O during the combustion process results from a complex series of reactions and is dependent upon many factors. Operating factors impacting N_2O formation include combustion temperature, excess air, and sorbent feed rate. The N_2O formation resulting from SNCR depends upon the reagent used, the amount of reagent injected, and the injection temperature. Adjusting any of these factors can impact CO and/or NO$_X$ emissions, and a combined standard provides an owner/operator the maximum flexibility to reduce overall criteria and GHG emissions. Pulverized coal boilers tend to operate at sufficiently high temperatures so as to not generally have significant N_2O emissions. On the other hand, fluidized bed boilers operate at lower temperatures and can have measurable N_2O emissions. However, the fuel flexibility benefit (*i.e.,* the ability to burn coal refuse and biomass) of fluidized bed boilers can help to offset the increase in N_2O emissions.

4. Commercial Demonstration Permit

The commercial demonstration permit section of the EGU NSPS was included in the original rulemaking in 1979 (44 FR 33580) to assure that the NSPS did not discourage the development of new and promising technologies. In the 1979 rule, the Administrator recognized that the innovative technology waiver provisions under CAA section 111(j) are not adequate to encourage certain capital intensive technologies. (44 FR 33580.) Under the innovative technology provisions, the Administrator may grant waivers for a period of up to 7 years from the date of issuance of a waiver or up to 4 years from the start of operation of a facility, whichever is less. The Administrator recognized that this time frame is not sufficient for amortization of high-capital-cost technologies. The commercial demonstration permit section established less stringent requirements for initial full-scale demonstration plants that received a permit in order to mitigate the potential impact of the rule on emerging technologies and insure that standards did not preclude the development of such technologies.

The authority to issue these permits was predicated on the DC Circuit Court's opinion in *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F. 2d 42 (DC Cir. 1973); NSPS should be set to avoid unreasonable costs or other impacts. Standards requiring a high level of performance, such as the proposed standards for PM, SO_2, and NO$_X$, might discourage the continued development of some new technologies. Owners/operators may view it as too risky to use new and untried or unproven technologies that have the potential to achieve greater continuous emission reductions than those required to be achieved under the new standards or achieve those reductions at a reduced cost. Thus, to encourage the continued development of new technologies that show promise in achieving levels of performance comparable to those of existing technologies, but at lower cost or with other offsetting environmental or energy benefits, special provisions are needed which encourage the development and use of new technologies, while ensuring that emissions will be minimized.

To mitigate the potential impact on emerging technologies, EPA is proposing to maintain similar standards to those finalized in 2006 for demonstration plants using innovative technologies. This should insure that the amended standards do not preclude the development of new technologies and should compensate for problems that may arise when applying them to commercial-scale units. Under the proposal, the Administrator (in consultation with DOE) would issue commercial demonstration permits for the first 1,000 MW of full-scale demonstration units of pressurized fluidized bed technology and EGUs using a multi-pollutant pollution control technology. Owners/operators of these units that are granted a commercial demonstration permit would be exempt from the amended standards and would instead be subject to less stringent emission standards. The proposed commercial demonstration permit standards for SO_2 and NO_X are similar to those finalized in 2006 and would avoid weakening existing standards while providing flexibility for innovative and emerging technologies. As discussed earlier, the proposed total PM standard of 0.034 lb/MMBtu approximates an equivalent stringency as the 2006 filterable PM standard of 0.015 lb/MMBtu. In addition, the first 1,000 MW of equivalent electrical capacity using advanced combustion controls to reduce NO_X emissions would be subject to an emissions standard of 1.0 lb/MWh (or 1.4 (lb NO_X + CO)/MWh).

The reason we selected these particular technologies is as follows. Multi-pollutant controls (*e.g.,* the Airborne Process™, the CEFCO process, Eco Power's COMPLY 2000, Powerspan's ECO®, ReACT™, Skyonic's SkyMine®, TOPSØE SNOX™, and the Pahlman process technology developed by Enviroscrub) offer the potential of reduced compliance costs and improved overall environmental performance. In addition, for boilers with exhaust temperatures that are too low for SCR (i.e., fluidized bed boilers) multi-pollutant controls are an alternative to SNCR. As discussed above, the use of SNCR can increase N_2O emissions. Since multi-pollutant controls use a different mechanism to reduce NO_X emissions, they do not necessarily result in additional N_2O formation. However, guaranteeing that the technologies could achieve the proposed standards on a continuous basis might discourage the deployment and demonstration of these technologies at EGUs. Pressurized fluidized bed technology has the potential to improve the efficiency and reduce the environmental impact of using coal to generate electricity. However, it is still a relatively undeveloped technology and has only been deployed on a limited basis worldwide. Allowing new pressurized beds to demonstrate compliance with slightly less stringent standards will help assure the NSPS does not discourage the development of this technology. Advanced combustion controls allow for the possibility of developing EGUs with low NO_X emissions while minimizing the need to install and operate SNCR or SCR. Advanced combustion controls reduce compliance costs, parasitic energy requirements, and ammonia emissions. Allowing the Administrator to approve commercial demonstration permits would limit regulatory impediments to improvements in combustion controls. If the Administrator subsequently finds that a given emerging technology (taking into consideration all areas of environmental impact, including air, water, solid waste, toxics, and land use) offers superior overall environmental performance, alternative standards could then be established by the Administrator. Technologies considered as nothing more than modified versions of existing demonstrated technologies will not be viewed as emerging technologies and will not be approved for a commercial demonstration permit. We are requesting comment on additional technologies that should be considered and the maximum magnitude of the demonstration permits.

5. Other Exemptions

Because filterable PM emissions are generally negligible for boilers burning natural gas or low sulfur oil, eliminating the PM standard for owners/operators of natural gas and low sulfur oil-fired EGUs would both help harmonize the various steam generating unit NSPS and lower the compliance burden without increasing emissions. Similarly, eliminating the opacity standard for owners/operators of natural gas-fired EGUs would reduce testing and monitoring requirements that do not result in any emissions benefit.

As municipal solid waste (MSW) combustors and CISWI units increase in size it is possible that they could generate sufficient electricity to become subject to the EGU NSPS. We have concluded that it is more appropriate to regulate these units under the CAA section 129 regulations and are, therefore, proposing to exempt owners/operators of affected facilities subject to the standards of performance for large MSW combustors (40 CFR part 60, subpart Eb) and CISWI (40 CFR part 60, subpart CCCC) from complying with the otherwise applicable standards for pollutants that those subparts address. The PM, SO_2, and NO_X standards in 40 CFR part 60, subpart Eb, are averaged over a daily basis and the PM, SO_2, and NO_X standards in 40 CFR part 60, subpart CCCC, do not require CEMS and are based on performance test data. The standards are either approximately equivalent to or more stringent than the present standards in 40 CFR part 60, subpart Da, so this proposed amendment would simplify compliance for owner/operators of MSW combustors and CISWI without an increase in emissions.

Similarly, in the final 2007 steam generating unit amendments (72 FR 32,710) we inadvertently expanded the applicability of 40 CFR part 60, subpart Db, to include industrial boilers combusting black liquor and distillate oil at Kraft pulp mills. Even though the distillate oil is generally low sulfur and would otherwise be exempt from the PM standards in 40 CFR part 60, subpart Db, the boilers use ESPs and the addition of "not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions" to the oil-fired exemption inadvertently expanded the applicability to owners/operators of boilers currently subject to the standards of performance for Kraft pulp mills (40 CFR part 60, subpart BB). Because 40 CFR part 60, subpart BB, includes a PM standard, we have concluded it is more appropriate to only regulate PM emissions from these units under 40 CFR part 60, subpart BB, and are, therefore, proposing to exempt these units from the PM standard under 40 CFR part 60, subpart Db. The PM standard in 40 CFR part 60, subpart BB, is approximately equivalent in stringency to the one in 40 CFR part 60, subpart Db, prior to the recent amendments, so this proposed amendment would simplify compliance for owner/operators of Kraft pulp mills without an increase in emissions.

We are also proposing to exempt owners/operators of IBs that meet the applicability requirements and that are complying with the SO_2 standard in 40 CFR part 60, subpart Ja (standards of performance for petroleum refineries) from complying with the otherwise applicable SO_2 limit in 40 CFR part 60, subpart Db. The SO_2 standard in 40 CFR part 60, subpart Ja, is more stringent than in 40 CFR part 60, subpart Db, so this proposed amendment would simplify compliance for owner/operators of petroleum refineries without an increase in pollutant emissions.

C. Changes to the Affected Facility

The present definition of a steam generating unit under 40 CFR part 60, subpart Da, starts at the coal bunkers and ends at the stack breeching. It includes the fuel combustion system (including bunker, coal pulverizer, crusher, stoker, and fuel burners, as applicable), the combustion air system, the steam generating system (firebox, boiler tubes, *etc.*), and the draft system (excluding the stack). This definition works well for traditional coal-fired EGUs, but does not account for potential efficiency improvements that have become available since 40 CFR part 60, subpart Da, was originally promulgated and are recognized through the use of output-based standards.

The proposed rule revision to include integrated CTs and/or fuel cells in the definition of a steam generating unit would increase compliance flexibility and decrease costs. Although we are not aware of any EGUs that have presently integrated either device, using exhaust heat for reheating or preheating boiler feedwater, preheating combustion air, or using the exhaust directly in the boiler to generate steam has high theoretical incremental efficiencies. In addition, using exhaust heat to reheat boiler feedwater would minimize the steam otherwise extracted from the steam turbine used for the reheating process and increase the theoretical electric output for an equivalent sized boiler. Because the exhaust from either an integrated CT or fuel cell would likely not be exhausted through the primary boiler stack, we are requesting comment on the appropriate emissions monitoring for these separate stacks. Because these emissions would likely be relatively small compared to the boiler, we are considering allowing emissions to be estimated using procedures that are similar to those used in the acid rain trading programs as an alternative to an NO_X CEMS. The CT or fuel cell emissions and electric output would be added to the boiler/steam turbine outputs.

D. Additional Proposed Amendments

Petroleum Coke. Petroleum coke, a carbonaceous material, is a by-product residual from the thermal cracking of heavy residual oil during the petroleum refining process and is a potentially useful boiler fuel. It has a superior heating value and lower ash content than coal and has historically been priced at a discount compared to coal. However, depending on the original crude feedstock, it may contain greater concentrations of sulfur and metals. At the time 40 CFR part 60, subpart Da, was originally promulgated, petroleum coke was not considered to be “created for the purpose of creating useful heat” and, hence, was not considered a “fossil fuel.” However, we have concluded that because petroleum coke has similar physical characteristics to coal, owners/operators of EGUs burning petroleum coke can cost effectively achieve the proposed standards. Due to the increased use of heavier crudes and more efficient processing of refinery residuals, U.S. and worldwide production of petroleum coke is increasing and is expected to continue to grow. Therefore, we expect owners/operators of EGUs to increase their use of petroleum coke in the future. Consistent with the EGU NESHAP, we are proposing to add petroleum coke to the definition of petroleum.

We are requesting comment on whether petroleum coke should be added to the definition of coal instead of petroleum. Both 40 CFR part 60, subparts Db and Dc, the large and small IB NSPS, include petroleum coke under the definition of coal. Including petroleum coke under coal would be consistent with the IB NSPS. However, the proposed emission standards are fuel neutral and because the revised definition would only apply to affected facilities that begin construction, modification, or reconstruction after the proposal date the impact on the regulated community would be the same if we added petroleum coke to the definition of coal as it would if we added it to the definition of petroleum.

Continuous Opacity Monitoring Systems (COMS). We have concluded that a BLDS and an ESP predictive model provide sufficient assurance that the filterable PM control device is operating properly such that a COMS is no longer necessary. Allowing this flexibility across the various steam generating unit NSPS would increase flexibility and decrease compliance costs without reducing environmental protection.

Titles of 40 CFR part 60, subparts D and Da. We are proposing to simplify the titles, but not amending the applicability, of 40 CFR part 60, subparts D and Da. The end of the titles “for Which Construction Is Commenced After August 17, 1971” and “for Which Construction is Commenced After September 18, 1978” respectively are unnecessary and potentially confusing.

E. Request for Comments on the Proposed NSPS Amendments

We request comments on all aspects of the proposed amendments. All significant comments received will be considered in the development and selection of the final amendments. We specifically solicit comments on additional amendments that are under consideration. These potential amendments are described below.

Net Output. The current output-based emission limit for PM, SO_2, and NO_X uses gross output, and the proposal includes standards that are based on gross energy output. In general, about 5 percent of station power is used internally by parasitic energy demands, but these parasitic loads vary on a source-by-source basis. To provide a greater incentive for achieving overall energy efficiency and minimizing parasitic loads, we would prefer to base output-based standards on net-energy output. However, it is our understanding that requiring a net output approach could result in monitoring difficulties and unreasonable monitoring costs at modified units. Demonstrating compliance with net-output based standards could be particularly problematic at existing units with both affected and unaffected facilities and units with common controls and/or stacks. Monitoring net output for new and reconstructed units can, on the other hand, be designed into the facility at low costs. To recognize the environmental benefit of overall environmental performance, we are considering establishing a net output-based emission standards for new and reconstructed units in the final rule in lieu of gross output-based standards.

In addition to recognizing the environmental benefit of minimizing the internal parasitic energy demand generally, net output based standards would serve to further recognize the environmental benefits of the use of supercritical steam conditions because parasitic loads tend to be lower for units using supercritical steam conditions compared to subcritical steam conditions. Furthermore, although the gross efficiencies of IGCC units are projected to be several percentage points higher than a comparable PC facility using supercritical steam conditions, the parasitic energy demands at IGCC units are expected to be much higher at approximately 15 percent. Consequently, on a net output basis, the efficiencies are comparable. Because we do not have continuous net output data available, we are considering assuming 5 percent parasitic losses to convert the gross output values to net output. We are requesting comments on the appropriate conversion factor.

Combined Heat and Power. We are requesting comment on whether it is appropriate to recognize the environmental benefit of electricity generated by CHP units by accounting for the benefit of on-site generation which avoids losses from the transmission and distribution of the electricity. Actual line losses vary from location to location, but if we adopt this provision in the final rule, we are considering a benefit of 5 percent avoided transmission and distribution losses when determining the electric output for CHP units. To assure that only well balanced units would be eligible; this provision would be restricted to units where the useful thermal output is at least 20 percent of the total output.

Opacity. We are requesting comment on the appropriate opacity monitoring procedures for owners/operators of affected facilities that are subject to an opacity standard but are not required to install a COMS. The present monitoring requirements as amended on January 20, 2011 (76 FR 3,517) require Method 9 performance testing every 12 months for owners/operators of affected facilities with no visible emissions, performance testing every 6 months for owners/operators of affected facilities with maximum opacity readings of 5 percent of less, performance testing every 3 months for owners/operators of affected facilities with maximum opacity readings of between 5 to 10 percent, and performance testing every 45 days for owners/operators of affected facilities with maximum opacity readings of greater than 10 percent. We are requesting comment on revising the schedule to require owners/operators of affected facilities with maximum opacity readings of 5 percent or less to conduct annual performance testing. To further reduce the compliance burden for owners/operators of affected facilities that intermittently use backup fuels with opacity of 5 percent or less (*i.e.,* natural gas with distillate oil backup), we are requesting comment on allowing Method 9 performance testing to be delayed until 45 days after the next day that a fuel with an opacity standard is combusted. The required performance testing for owners/operators of affected facilities with maximum opacity readings between 5 to 10 percent would be required to be performed within 6 months. The required performance testing for owners/operators of affected facilities with maximum opacity readings greater than 10 percent would be required to be performed within 3 months. In addition, the alternate Method 22 visible observation approach requires 30 operating days of no visible emissions to qualify for the reduced monitoring procedures. We are requesting comment on only requiring either 5 or 10 days of observation with no visible emissions to qualify for the reduced periodic monitoring.

In general, the level of filterable PM emissions and the resultant opacity from oil-fired steam generating units is a function of the completeness of fuel combustion as well as the ash content in the oil. Distillate oil contains negligible ash content, so the filterable PM emissions and opacity from distillate oil-fired steam generating units are primarily comprised of carbon particles resulting from incomplete combustion of the oil. Naturally low sulfur crude oil and desulfurized oils are higher quality fuels and exhibit lower viscosity and reduced asphaltene, ash, and sulfur content, which result in better atomization and improved overall combustion properties. To provide additional flexibility and decrease the compliance burden on affected facilities, we are requesting comment on whether the opacity standard should be eliminated for owners/operators of affected facilities burning ultra low sulfur (*i.e.,* 15 ppm sulfur) distillate oil.

We are also requesting comment on amending the opacity requirements for owners/operators of affected facilities using PM CEMS, but not complying with the PM standard under 40 CFR part 60, subpart Da. Owners/operators of these facilities are subject to an opacity standard and are required to periodically monitor opacity. We are requesting comment on the appropriateness of waiving all opacity monitoring for owners/operators of these affected facilities. In addition, we are also requesting comment on allowing owners/operators of 40 CFR part 60, subpart D, affected facilities that opt to comply with the 40 CFR part 60, subpart Da, PM standard and qualify for the corresponding opacity exemption to opt back out. (Under the existing rule, once a 40 CFR part 60, subpart D, affected facility opts to comply with the 40 CFR part 60, subpart Da, PM standard in order to qualify for the corresponding opacity exemption, it cannot subsequently opt to go back to complying with the 40 CFR part 60, subpart D, PM standard.) Finally, we are requesting comment on the appropriateness of eliminating the opacity standard for owners/operators of 40 CFR part 60, subpart D, affected facilities using PM CEMS even if they are not complying with the 40 CFR part 60, subpart Da, PM standard. Consistent with paragraph 40 CFR 60.11(e), as long as these facilities demonstrate continuous compliance with the applicable PM standard on a 3-hour average, the opacity standard would not apply.

In addition, we are requesting comment on eliminating the opacity standard for owners/operators of affected facilities complying with a total PM standard of 15 ng/J (0.034 lb/MMBtu) or less that use control equipment parameter monitoring or some other continuous monitoring approach to demonstrate compliance with that standard. Based on the PM performance test data collected as part of the 2010 ICR, at this total PM emissions rate the filterable portion is expected to be significantly lower than the original 40 CFR part 60, subpart Da, filterable PM standard, 0.030 lb/MMBtu. As described in the 2006 NSPS amendments, at filterable PM emissions at this level, opacity is less useful and eliminating the standards would simplify compliance without decreasing environmental protection.

IGCC Units. We are requesting comment on whether an IGCC unit that co-produces hydrocarbons or hydrogen should be subject to the CT NSPS instead of the EGU NSPS. The original rationale for including IGCC units in the EGU NSPS is that it is simply another process for converting coal to electricity. However, an IGCC that co-produces hydrocarbons or hydrogen would convert a substantial portion of the original energy in the coal to useful chemicals instead of to measurable useful electric and thermal output. Using net-output based standards in this situation would be difficult because a portion of the parasitic load would be attributed to the production of the useful chemicals and it would not be possible to apportion this easily. To avoid owners/operators from producing a small amount of hydrocarbons/hydrogen to avoid being subject to 40 CFR part 60, subpart Da, we are requesting comment on the percentage of coal that must be converted to useful chemical products to quality for regulation under the stationary CT NSPS. We are presently considering between 10 to 20 percent. We are also requesting comment on whether there is a way to effectively account for the parasitic losses such attributable to production of the useful chemicals.

Elimination of Existing References. To simplify compliance and improve the readability of 40 CFR part 60, subpart Da, we are requesting comment on deleting the "emergency condition" requirement for the SO_2 standard exemption, references to percent reductions for NO_X and PM, references to solvent refined coal, and the existing commercial demonstration permit references. The emergency condition requirement was originally included in 40 CFR part 60, subpart Da, as an alternative to excluding periods of malfunction. The provision was intended to avoid power supply disruptions while also minimizing operation of affected facilities without operation of SO_2 controls. However, the reliability of FGD technology has been demonstrated since 40 CFR part 60, subpart Da, was originally promulgated and malfunctions are uncommon events. Furthermore, the Transport Rule provides a financial incentive to operate SO_2 control equipment at all times. Therefore, we would delete references to the emergency condition requirement and simply exclude periods of malfunction from the SO_2 standard for owners/operators of affected facilities presently subject to 40 CFR part 60, subpart Da.

The 1990 CAA amendments removed the requirement that standards be based on a percent reduction. The percent reduction requirements for NO_X and PM have been superseded by the numerical limits for owners/operators of existing units and deleting these references would improve the readability of the subpart. Similarly, we are not aware of any affected facility burning solvent refined coal or operating under the existing commercial demonstration permit. Because these provisions have been superseded, deleting these references would improve the readability of the subpart.

The IB NSPS currently does not credit fuel pretreatment toward compliance with the SO_2 percent reduction standard unless the fuel pretreatment results in a 50 percent or greater reduction in the potential SO_2 emissions rate and results in an uncontrolled SO_2 emissions rate of equal to less than 0.60 lb/MMBtu. We are requesting comment on whether these restrictions discourage the development and use of cost-effective fuel pretreatment technologies and increase costs to the regulated community. To the extent that this restriction could be eliminated without adversely impacting protection of the environment, we are considering eliminating this restriction. We are also requesting comment on other provisions in the steam generating unit NSPS that could be eliminated to reduce regulatory burden without decreasing environmental protection.

The large IB NSPS (40 CFR part 60, subpart Db) currently includes regulatory language for standards for boilers burning MSW. This language was included to assure the broad applicability of 40 CFR part 60, subpart Db. However, subsequent to the original promulgation of 40 CFR part 60, subpart Db, EPA promulgated specific standards for MWCs and exempted owners/operators of MWCs from 40 CFR part 60, subpart Db. We are requesting comment on deleting all references to MSW in 40 CFR part 60, subpart Db. This would simplify compliance and readability of the rule without increasing emissions to the environment. Owners/operators of these units would still be subject to emission standards under 40 CFR part 60, subpart Db, if they stop burning MSW.

Coal Refuse. The high ash and corresponding low Btu content of coal refuse results in lower efficiencies than comparable coal-fired EGUs. Therefore, we are requesting comment on the environmental impact of subcategorizing coal refuse-fired EGUs and maintaining the existing NO_X standard of 1.0 lb/MWh (or 1.4 lb [NO_X + CO]/MWh) for owners/operators of these units.

Temporary Boilers. On occasion, owners/operators of industrial facilities need to bring in temporary boilers for steam production for short-term use while the primary steam boilers are not available. The existing testing and monitoring requirements for IB may not be appropriate for temporary boilers used for less than 30 days. We intend to establish alternate testing and monitoring requirements for owners/operators of temporary IBs and are requesting comment on the appropriate requirements.

IX. Summary of Cost, Environmental, Energy, and Economic Impacts of This Proposed NSPS

In setting the standards, the CAA requires us to consider alternative emission control approaches, taking into account the estimated costs and benefits, as well as the energy, solid waste and other effects. EPA requests comment on whether it has identified the appropriate alternatives and whether the proposed standards adequately take into consideration the incremental effects in terms of emission reductions, energy and other effects of these alternatives. EPA will consider the available information in developing the final rule.

The costs, environmental, energy, and economic impacts are typically expressed as incremental differences between the impacts on owners/operators of units complying with the proposed amendments relative to complying with the current NSPS emission standards (*i.e.,* baseline). However, for EGUs this would not accurately represent actual costs and benefits of the proposed amendments. Requirements of the NSR program often result in new EGUs installing controls beyond what is required by the existing NSPS. In addition, owners/operators of new EGUs subject to the requirements of the Transport Rule will likely elect to minimize operating costs by operating at SO_2 and NO_X emission rates lower than what is required by the existing NSPS. Finally, the proposed EGU NESHAP PM and SO_2 standards for new EGUs are as stringent as or more stringent than the proposed NSPS amendments, and we have concluded that there are no costs or benefits associated with these amendments. We are requesting comment on this conclusion.

To establish the regulatory baseline for NO_X emissions, we reviewed annual NO_X emission rates for units operating at levels below the existing NSPS NO_X standard that commenced operation between 2005 and 2008 and that reported both NO_X emissions and gross electric output data to CAMD. The 2009 average annual NO_X emissions rate for these units was 0.61 lb/MWh. To account for the variability in performance of presently used NO_X controls, we concluded that 30-day averages are typically ¼ to ⅓ higher than annual average emission rates and used 0.80 lb/MWh as the baseline. This represents an approximate 12 percent reduction in the growth of NO_X emissions from new units that would be subject to the proposed standards. We have concluded that a combined NO_X/CO standard would have similar impacts because CO controls are based on readily available combustion controls. The additional monitoring costs for a combined standard would include additional CEMS certification because many facilities currently have CO CEMS for operational control.

Although multiple coal-fired EGUs have recently commenced operation and several are currently under construction, no new coal-fired EGUs have commenced construction in either 2009 or 2010. In addition, forecasts of new generation capacity from both the EIA and the Edison Electric Institute do not project any new coal-fired EGUs being constructed in the short term. This is an indication that, in the near term, few new coal-fired EGUs will be subject to the NSPS amendments. Because the use of natural gas in boiler/

steam turbine-based EGUs is an inefficient use of natural gas to generate electricity, all new natural gas-fired EGUs built in the foreseeable future will most likely be combined cycle units or CT peaking units and, thus, not subject to 40 CFR part 60, subpart Da, but instead subject to the NSPS for stationary CTs (40 CFR part 60, subpart KKKK). Furthermore, because of fuel supply availability and cost considerations, we assumed that no new oil-fired EGUs will be built during the next 5 years.

Therefore, we are not projecting that any new, reconstructed, or modified steam generating units would become subject to the proposed amendments over the next 5 years. Even though we are not projecting any impacts from the proposed amendments, in the event a new steam generating units does become subject the proposed amendments we have concluded that the proposed amendments would be appropriate. For more information on these impacts, please refer to the economic impact analysis and technical support documents in the public docket.

X. Impacts of These Proposed Rules

A. What are the air impacts?

Under the proposed Toxics Rule, EPA projects annual HCl emissions reductions of 91 percent in 2015, Hg emissions reductions of 79 percent in 2015, and $PM_{2.5}$ emissions reductions of 29 percent in 2015. In addition, EPA projects SO_2 emission reductions of 53 percent, annual NO_X emissions reductions of 7 percent, and annual CO_2 reductions of 1 percent from the power sector by 2015, relative to the base case. See Table 21.

TABLE 21—SUMMARY OF POWER SECTOR EMISSIONS REDUCTIONS (TPY)

	SO_2 (million tons)	NO_X (million tons)	Mercury (tons)	HCl (thousand tons)	$PM_{2.5}$ (thousand tons)	CO_2 (million metric tonnes)
Base Case	3.9	2.0	29	78	286	2,243
Proposed Toxics Rule	1.8	1.9	6	10	202	2,219
Change	−2.1	−0.1	−23.0	−68	−83.2	−24.2

B. What are the energy impacts?

Under the provisions of this proposed rule, EPA projects that approximately 9.9 GW of coal-fired generation (roughly 3 percent of all coal-fired capacity and 1% of total generation capacity in 2015) may be removed from operation by 2015. These units are predominantly smaller and less frequently used generating units dispersed throughout the area affected by the rule. If current forecasts of either natural gas prices or electricity demand were revised in the future to be higher, that would create a greater incentive to keep these units operational.

EPA also projects fuel price increases resulting from the proposed Toxics Rule. Average retail electricity prices are shown to increase in the continental U.S. by 3.7 percent in 2015. This is generally less of an increase than often occurs with fluctuating fuel prices and other market factors. Related to this, the average delivered coal price increases by less than 1 percent in 2015 as a result of shifts within and across coal types. EPA also projects that electric power sector-delivered natural gas prices will increase by about 1 percent over the 2015–2030 timeframe and that natural gas use for electricity generation will increase by about less than 300 billion cubic feet (BCF) over that horizon. These impacts are well within the range of price variability that is regularly experienced in natural gas markets. Finally, the EPA projects coal production for use by the power sector, a large component of total coal production, will decrease by 20 million tons in 2015 from base case levels, which is less than 2 percent of total coal produced for the electric power sector in that year.

C. What are the compliance costs?

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the base case and policy case in which the sector pursues pollution control approaches to meet the proposed Toxics Rule HAP emission standards. In simple terms, these costs are the resource costs of what the power industry will directly expend to comply with EPA's requirements.

EPA projects that the annual incremental compliance cost of the proposed Toxics Rule is $10.9 billion in 2015 ($2007). The annualized incremental cost is the projected additional cost of complying with the proposed rule in the year analyzed, and includes the amortized cost of capital investment and the ongoing costs of operating additional pollution controls, needed new capacity, shifts between or amongst various fuels, and other actions associated with compliance.

End-use energy efficiency can be an important part of a compliance strategy for this regulation. It can reduce the cost of compliance, lower consumer costs, reduce emissions, and help to ensure reliability of the U.S. power system. Policies to promote end-use energy efficiency are largely outside of EPA's direct control. However this rule can provide an incentive for action to promote energy efficiency. To examine the potential impacts of Federal and state energy efficiency policies, EPA used the Integrated Planning Model (IPM).

An illustrative Energy Efficiency Scenario was developed and run as a sensitivity for both the Base Case and the Toxics Rule Case. The illustrative Energy Efficiency Case assumed adoption of two key energy efficiency policies. First, it assumed that states adopted rate-payer funded energy efficiency programs, such as energy efficiency resource standards, integrated resource planning and demand side management plans. Examples of energy efficiency programs that might be driven by these policies include rebate programs for efficient products and state programs to provide technical assistance and information for energy efficient home retrofits. The electricity demand reduction that could be gained from these programs was taken from work done by Lawrence Berkley National Laboratory (LBNL).[179] Second, the Department of Energy (DOE) provided estimates of the demand reductions that could be achieved from implementation of appliance efficiency standards mandated by existing statutes but not yet implemented (appliance standards that have been implemented are in the base case.) EPA assumed that these policies are used beyond the timeframe of the DOE and LBNL estimates (2035

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[179] The Shifting Landscape of Ratepayer Funded Energy Efficiency in the U.S., Galen Barbose *et al.*, October 2009, Lawrence Berkeley National Laboratory, LBNL–2258E.

and 2020 respectively) so that their impacts continue through 2050. Table 22 below gives the electricity demand reductions that these two policies would yield.

TABLE 22—ENERGY EFFICIENCY SENSITIVITY RESULTS: ELECTRICITY DEMAND REDUCTIONS

(all in TWh)	*2009*	*2012*	*2015*	*2020*	*2030*	*2040*	*2050*
Ratepayer-funded EE Programs		59	110	174	198	198	198
% of U.S. Demand		1.5%	2.7%	4.1%	4.2%	3.9%	3.6%
Federal Appliance Standards		0	6	52	112	114	124
% of U.S. Demand		0.0%	0.2%	1.2%	2.4%	2.2%	2.2%
Total EE Demand Reductions		59	117	226	310	312	322
% of U.S. Demand		1.5%	2.9%	5.3%	6.6%	6.1%	5.8%
U.S. Electricity Demand (EPA Reference)	3,838	4,043	4,086	4,302	4,703	5,113	5,568
Average Annual Growth Rate (2009 to 20xx)			1.05%	1.04%	0.97%	0.93%	0.91%
Net Demand after EE	3,838	3,984	3,969	4,076	4,392	4,801	5,246
Average Annual Growth Rate (2009 to 20xx)			0.56%	0.55%	0.64%	0.73%	0.77%

As shown, these policies are estimated to result in a moderate reduction in U.S. electricity demand climbing to over five percent by 2020 and averaging over five percent from 2020 to 2050. These reductions lower annual average electricity demand growth (from 2009 historic data) through 2020 relative to the reference forecast from 1.04 percent to 0.55 percent.

The effects of the Energy Efficiency Scenario on the projected total electricity generating costs of the power sector are shown below in Table 23. In this table we see the projected costs in the Base and Toxics Rule Cases with and without energy efficiency.

TABLE 23—EFFECT OF ENERGY EFFICIENCY POLICY ON GENERATION SYSTEM COSTS

Total costs (billion 2007$)—IPM + Total EE	2015	2020	2030
Base	144	155	200
Base + EE	142	150	190
Toxics Rule	155	165	210
Toxics Rule + EE	153	159	199
1. Increment (Base to Base + EE)	−2	−5	−11
2. Increment (Toxics Rule to Toxics Rule + EE)	−2	−6	−11
3. Increment (Base to Toxics Rule)	11	10	10
4. Increment (Base + EE to Toxics Rule + EE)	11	9	9
5. Increment (Base to Toxics Rule) to (Base + EE to Toxics Rule + EE)	0	−1	−1
6. Increment (Base to Toxics Rule + EE)	9	4	−1

In this analysis, the costs of the energy efficiency policies are treated as a component of the cost of generating electricity and are imbedded in the costs seen in Table 23. The modeling estimated that these energy efficiency policies would reduce the total cost of implementing the rule by billions of dollars. EPA looked at a case in which these energy efficiency policies were in place with and without the Toxics Rule. As Table 23 shows, with or without the Toxics Rule, energy efficiency policies reduce the overall costs to generate electricity. The cost reductions increase over time. When comparing the Toxics Rule Case without energy efficiency to the Toxics Rule Case with energy efficiency, the analysis shows that these energy efficiency policies could reduce overall system costs by $2 billion in 2015, $6 billion in 2020, and $11 billion in 2030.

The energy savings driven by these energy efficiency policies, and corresponding lower levels of demand, translate into reductions in electricity prices. EPA's modeling shows that the Toxics Rule increases retail prices by 3.7 percent, 2.6 percent and 1.9 percent in 2015, 2020 and 2030, respectively, relative to the base case. If energy efficiency policies are implemented, the price increase would be smaller in 2015 when retail prices would increase by 3.3 percent. In 2020 and 2030 the reduced demand for electricity is sufficient to reduce the retail price of electricity relative to the Base Case even with the Toxics Rule. If the Toxics Rule is implemented with energy efficiency, retail electricity prices decrease by about 1.6 percent in 2020 and by about 2.3 percent in 2030 relative to the Base.[180] The effect on average electricity bills, however, may fall more than these percentages as energy efficiency means that less electricity will be used by consumers of electricity.

In the Energy Efficiency Cases, IPM projects considerably more plant retirements than in the Base and Policy Cases. The Base Case with Energy Efficiency in 2020 shows twice as much capacity retiring, and more than double the capacity of coal plant retirements as the Base Case without energy efficiency. The Toxics Rule would increase the amount of capacity retired over the Base Case by 8 GW. If the energy efficiency policies were imposed as the power sector was taking action to come into compliance, the effect of the Toxics Rule on plant retirements would be greater with an additional 25 GW of

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[180] Source: EPA's Retail Electricity Price Model.

retirements in 2020. These results are shown in Table 24 below.

TABLE 24—EFFECT OF ENERGY EFFICIENCY ON RETIREMENTS

Retirements Grand Total & (Coal) (GW)	2015	2020	2030
Base	27 (5)	27 (5)	27 (5)
Base + EE	38 (12)	54 (12)	53 (12)
Toxics Rule	35 (15)	35 (14)	35 (14)
Toxics Rule + EE	47 (25)	60 (24)	60 (24)
1. Increment (Base to Base + EE)	11 (7)	27 (7)	26 (7)
2. Increment (Toxics Rule to Toxics Rule + EE)	11 (10)	25 (10)	24 (10)
3. Increment (Base to Toxics Rule)	9 (10)	8 (9)	8 (9)
4. Increment (Base + EE to Toxics Rule + EE)	9 (13)	6 (12)	6 (12)
5. Increment (Base to Toxics Rule) to (Base + EE to Toxics Rule + EE)	0 (3.0)	−2 (3)	−2 (3)
6. Increment (Base to Toxics Rule + EE)	20 (20)	33 (19)	32 (19)

In effect, the timely adoption and implementation of energy efficiency policies would augment currently projected reserve capacities that are instrumental to assuring system reliability.

The addition of energy efficiency policies during and beyond the Toxics Rule compliance period can result in very modest reductions in air emissions. This is largely due to lower levels of electricity generation. As a result, with energy efficiency policies the Toxics Rule would achieve reductions of approximately an additional 520 pounds of Hg emissions, an additional 80,000 tons of SO_2, and an additional 110,000 tons of NO_X in 2020.

Although EPA cannot mandate energy efficiency policies, the positive effects of these policies on the cost of rule to industry and consumers could be a strong incentive to undertake them as a part of an overall compliance strategy.

Table 25 presents estimated breakouts of the cost of reducing certain key pollutants under the Toxics Rule. Because many of the strategies to reduce pollutants are multi-pollutant in nature, it is not possible to create a technology-specific breakout of costs (*e.g.* a baghouse reduces $PM_{2.5}$ as well as Hg, it also reduces the cost of using additional sorbents to reduce acid gases or further reduce Hg). Costs were first calculated by using representative unit costs for each control option. These costs were then multiplied by the amount of capacity that employed the given control option. Costs were then pro-rated amongst the pollutants that a given technology reduced. This pro-ration was based on rough estimates of the percentage reduction expected for a given pollutant (*e.g.* because a baghouse alone removes significant amounts of $PM_{2.5}$ and has a much smaller Hg reduction, most of the baghouse cost was assigned to $PM_{2.5}$, in the case of ACI (which often includes a baghouse) reductions of Hg and fine PM were similar, therefore costs were pro-rated more equally). Since total costs from the bottom up calculation did not exactly match our total modeled costs, the pollutant by pollutant costs were then pro-rated to equal the total model costs.

TABLE 25—BREAKOUTS OF COSTS BY CONTROL MEASURE AND POLLUTANT FOR THE PROPOSED TOXICS RULE

		Dry FGD + FF	DSI	FF	ACI	Scrubber upgrade	Waste coal FGD	Total
Total (2007 $MM)	Capital	1,421	428	1,092	1,498	669	94	5,201
	FOM	252	71	41	45	0	20	431
	VOM	377	1,241	105	627	0	66	2,416
	2015 Annual Capital + FOM + VOM.	2,050	1,740	1,238	2,173	669	179	8,048
Cost Share	HCl	29%	56%	0%	0%	52%	29%	
	Hg	10%	0%	10%	51%	0%	10%	
	$PM_{2.5}$	32%	0%	90%	49%	0%	32%	
	SO_2	29%	44%	0%	0%	48%	29%	
Total Annual Costs, 2015 (2007 $MM).	HCL	588	979	0	0	347	51	1,965
	Hg	205	0	124	1,106	0	18	1,453
	$PM_{2.5}$	654	0	1,114	1,067	0	57	2,892
	SO_2	603	761	0	0	322	53	1,739
	TOTAL	2,050	1,740	1,238	2,173	669	179	8,048

	Capital + FOM + VOM Costs	Fuel cost	Total cost	Share of total cost	Capital share	Tons reduced	$/ton ($/lb for Hg)	General range of costs from other MACT rules
Acid Gasses (HCl + HCN + HF)	1,965	1,064	3,029	24%	37%	106,038	$18,529	$2,500–$55,000
Hg	1,453	825	2,277	18%	49%	18	$40,428	$1,250–$55,200
$PM_{2.5}$	2,892	357	3,249	36%	74%	83,246	$34,742	$1,600–$55,000
SO_2	1,739	645	2,384	22%	44%	2,050,871	$848	$540–$5,100
Total	8,048	2,892	10,940	100%				

D. What are the economic impacts?

For this proposed rule, EPA analyzed the costs using IPM. IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for a variety of HAP and other pollutants throughout the contiguous U.S. for the entire power system.

Documentation for IPM can be found in the docket for this rulemaking or at *http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html*.

EPA also included an analysis of impacts of the proposed rule to industries outside of the electric power sector by using the Multi-Market Model. This model is a partial equilibrium model that includes 100 sectors that cover energy, manufacturing, and service applications and is designed to capture the short-run effects associated with an environmental regulation. It was used to estimate economic impacts for the recently promulgated Industrial Boiler major and area source standards and CISWI standard.

We use the Multi-Market model to estimate the social cost of the proposed rule. Using this model, we estimate the social costs of the proposal to be $10.9 billion (2007$), which is almost identical to the compliance costs. The usefulness of a Multi-Market model in predicting the estimated effects is limited because the electric power sector affects all sectors of the economy. For the final rule, we will be refining the social cost estimates with general equilibrium models, including an assessment with our upgraded CGE model, EMPAX. Commenters are encouraged to provide other general equilibrium model platforms and to provide other information to refine the social cost assessments for the final rule.

EPA also performed a screening analysis for impacts on small entities by comparing compliance costs to sales/revenues (*e.g.,* sales and revenue tests). EPA's analysis found the tests were typically higher than 1 percent for small entities included in the screening analysis. EPA has prepared an Initial Regulatory Flexibility Analysis (IRFA) that discusses alternative regulatory or policy options that minimize the rule's small entity impacts. It includes key information about key results from the SBAR panel.

Although a stand-alone analysis of employment impacts is not included in a standard cost-benefit analysis, the current economic climate has led to heightened concerns about potential job impacts. Such an analysis is of particular concern in the current economic climate as sustained periods of excess unemployment may introduce a wedge between observed (market) wages and the social cost of labor. In such conditions, the opportunity cost of labor required by regulated sectors to bring their facilities into compliance with an environmental regulation may be lower than it would be during a period of full employment (particularly if regulated industries employ otherwise idled labor to design, fabricate, or install the pollution control equipment required under this proposed rule). For that reason, EPA also includes estimates of job impacts associated with the proposed rule. EPA presents an estimate of short-term employment opportunities as a result of increased demand for pollution control equipment. Overall, the results suggest that the proposed rule could support a net of roughly 31,000 job-years [181] in direct employment impacts in 2015.

The basic approach to estimate these employment impacts involved using projections from IPM from the proposed rule analysis such as the amount of capacity that will be retrofit with control technologies, for various energy market implications, along with data on labor and resource needs of new pollution controls and labor productivity from secondary sources, to estimate employment impacts for 2015. For more information, please refer to the TSD for this analysis, "Employment Estimates of Direct Labor in Response to the Proposed Toxics Rule in 2015."

EPA relied to Morgenstern, *et al.* (2002), identify three economic mechanisms by which pollution abatement activities can indirectly influence jobs:

Higher production costs raise market prices, higher prices reduce consumption, and employment within an industry falls ("demand effect");

Pollution abatement activities require additional labor services to produce the same level of output ("cost effect"); and

Post regulation production technologies may be more or less labor intensive (*i.e.,* more/less labor is required per dollar of output) ("factor-shift effect").

Using plant-level Census information between the years 1979 and 1991, Morgenstern, *et al.,* estimate the size of each effect for four polluting and regulated industries (petroleum, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million spending on pollution abatement results in an small net increase of 1.6 jobs; the estimated effect is not statistically significant different from zero. As a result, the authors conclude that increases in pollution abatement expenditures do not necessarily cause economically significant employment changes. The conclusion is similar to Berman and Bui (2001) who found that increased air quality regulation in Los Angeles did not cause large employment changes.[182] For more information, please refer to the RIA for this proposed rule.

The ranges of job effects calculated using the Morgenstern, *et al.*, approach are listed in Table 26.

TABLE 26—RANGE OF JOB EFFECTS FOR THE ELECTRICITY SECTOR

	Estimates using Morgenstern, *et al.* (2001)		Factor shift effect
	Demand effect	Cost effect	
Change in Full-Time Jobs per Million Dollars of Environmental Expenditure [a].	−3.56	2.42	2.68.
Standard Error	2.03	1.35	0.83.
EPA estimate for Proposed Rule [b]	−45,000 to +2,500	+4,700 to 24,000	+200 to 32,000.

[a] Expressed in 1987 dollars. See footnote a from Table 9–3 of the RIA for inflation adjustment factor used in the analysis.

[b] According to the 2007 Economic Census, the electric power generation, transmission and distribution sector (NAICS 2211) had approximately 510,000 paid employees.

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[181] Numbers of job years are not the same as numbers of individual jobs, but represents the amount of work that can be performed by the equivalent of one full-time individual for a year (or FTE). For example, 25 job years may be equivalent to five full-time workers for five years, 25 full-time workers for one year, or one full-time worker for 25 years.

[182] For alternative views in economic journals, see Henderson (1996) and Greenstone (2002).

EPA recognizes there may be other job effects which are not considered in the Morgenstern, *et al.*, study. Although EPA has considered some economy-wide changes in industry output as shown earlier with the Multi-Market model, we do not have sufficient information to quantify other associated job effects associated with this rule. EPA solicits comments on information (*e.g.*, peer-reviewed journal articles) and data to assess job effects that may be attributable to this rule.

E. What are the benefits of this proposed rule?

We estimate the monetized benefits of this proposed regulatory action to be \$59 billion to \$140 billion (2007\$, 3 percent discount rate) in 2016. The monetized benefits of the proposed regulatory action at a 7 percent discount rate are \$53 billion to \$130 billion (2007\$). These estimates reflect the economic value of the Hg benefits as well as the $PM_{2.5}$ and CO_2-related co-benefits.

Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[183] A summary of the monetized benefits estimates at discount rates of 3 percent and 7 percent is in Table 27 of this preamble.

TABLE 27—SUMMARY OF THE $PM_{2.5}$ MONETIZED CO-BENEFITS ESTIMATES FOR THE PROPOSED TOXICS RULE IN 2016

[Billions of 2007\$] [a]

	Estimated emission reductions (million tons per year)	Monetized $PM_{2.5}$ co-benefits (3% discount rate)	Monetized $PM_{2.5}$ co-benefits (7% discount rate)
$PM_{2.5}$ Precursors			
SO_2	2.1	\$58 to \$140	\$53 to \$130.
Total		\$58 to \$140	\$53 to \$130.

[a] All estimates are for the implementation year (2016), and are rounded to two significant figures. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary between precursors because each ton of precursor reduced has a different propensity to form $PM_{2.5}$. Benefits from reducing HAP are not included.

These benefits estimates represent the total monetized human health benefits for populations exposed to less $PM_{2.5}$ in 2016 from controls installed to reduce air pollutants in order to meet these standards. These estimates are calculated as the sum of the monetized value of avoided premature mortality and morbidity associated with reducing a ton of $PM_{2.5}$ and $PM_{2.5}$ precursor emissions. To estimate human health benefits derived from reducing $PM_{2.5}$ and $PM_{2.5}$ precursor emissions, we used the general approach and methodology laid out in Fann, *et al.* (2009).[184]

To generate the benefit-per-ton estimates, we used a model to convert emissions of $PM_{2.5}$ precursors into changes in ambient $PM_{2.5}$ levels and another model to estimate the changes in human health associated with that change in air quality. Finally, the monetized health benefits were divided by the emission reductions to create the benefit-per-ton estimates. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors because each ton of precursor reduced has a different propensity to form $PM_{2.5}$. For example, SO_X has a lower benefit-per-ton estimate than direct $PM_{2.5}$ because it does not form as much $PM_{2.5}$, thus the exposure would be lower, and the monetized health benefits would be lower.

For context, it is important to note that the magnitude of the PM benefits is largely driven by the concentration response function for premature mortality. Experts have advised EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. For this proposed rule we cite two key empirical studies, one based on the American Cancer Society cohort study[185] and the extended Six Cities cohort study.[186] In the Regulatory Impacts Analysis (RIA) for this proposed rule, which is available in the docket, we also include benefits estimates derived from expert judgments and other assumptions.

This analysis does not include the type of detailed uncertainty assessment found in the 2006 $PM_{2.5}$ NAAQS RIA because we lack the necessary air quality input and monitoring data to run the benefits model. However, the 2006 $PM_{2.5}$ NAAQS benefits analysis[187] provides an indication of the sensitivity of our results to various assumptions.

It should be emphasized that the monetized benefits estimates provided above do not include benefits from several important benefit categories, including reducing other air pollutants, ecosystem effects, and visibility impairment. The benefits from reducing various HAP have not been monetized in this analysis, including reducing 68,000 tons of HCl, and 3,200 tons of other metals each year. Although we do not have sufficient information or modeling available to provide monetized estimates for this rulemaking, we include a qualitative assessment of the health effects of these air pollutants in the RIA for this proposed rule, which is available in the docket.

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[183] Roman *et al.*, 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268–2274.

[184] Fann, N., C.M. Fulcher, B.J. Hubbell. 2009. "The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution." Air Qual Atmos Health (2009) 2:169–176.

[185] Pope *et al.*, 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." Journal of the American Medical Association 287:1132–1141.

[186] Laden *et al.*, 2006. "Reduction in Fine Particulate Air Pollution and Mortality." *American Journal of Respiratory and Critical Care Medicine.* 173: 667–672.

[187] U.S. Environmental Protection Agency, 2006. Final Regulatory Impact Analysis: $PM_{2.5}$ NAAQS. Prepared by Office of Air and Radiation. October. Available on the Internet at *http://www.epa.gov/ttn/ecas/ria.html.*

TABLE 28—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE PROPOSED RULE IN 2016

[Millions of 2006$] [a]

	3% Discount rate	7% Discount rate
Total Monetized Benefits [b]	$59,000 to $140,000	$53,000 to $130,000.
Hg-related Benefits [c]	$4.1 to $5.9	$0.45 to $0.89.
CO$_2$-related Benefits	$570	$570.
PM$_{2.5}$-related Co-benefits [d]	$59,000 to $140,000	$53,000 to $120,000.
Total Social Costs [e]	$10,900	$10,900.
Net Benefits	$48,000 to $130,000	$42,000 to $130,000.
Non-monetized Benefits	Visibility in Class I areas. Cardiovascular effects of Hg exposure. Other health effects of Hg exposure. Ecosystem effects. Commercial and non-freshwater fish consumption.	

[a] All estimates are for 2016, and are rounded to two significant figures. The net present value of reduced CO$_2$ emissions are calculated differently than other benefits. The same discount rate used to discount the value of damages from future emissions (SCC at 5, 3, 2.5 percent) is used to calculate net present value of SCC for internal consistency. This table shows monetized CO$_2$ co-benefits at discount rates at 3 and 7 percent that were calculated using the global average SCC estimate at a 3 percent discount rate because the interagency workgroup on this topic deemed this marginal value to be the central value. In section 6.6 of the RIA we also report the monetized CO$_2$ co-benefits using discount rates of 5 percent (average), 2.5 percent (average), and 3 percent (95th percentile).

[b] The total monetized benefits reflect the human health benefits associated with reducing exposure to MeHg, PM$_{2.5}$, and ozone.

[c] Based on an analysis of health effects due to recreational freshwater fish consumption.

[d] The reduction in premature mortalities account for over 90 percent of total monetized PM$_{2.5}$ benefits.

[e] Social costs are estimated using the MultiMarket model, in order to estimate economic impacts of the proposal to industries outside the electric power sector. Details on the social cost estimates can be found in Chapter 9 and Appendix E of the RIA.

For more information on the benefits and cost analysis, please refer to the RIA for this rulemaking, which is available in the docket.

XI. Public Participation and Request for Comment

We request comment on all aspects of this proposed rule.

During this rulemaking, we conducted outreach to small entities and convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of this proposed rule. As part of the SBAR Panel process we conducted outreach with representatives from various small entities that would be affected by this proposed rule. We met with these SERs to discuss the potential rulemaking approaches and potential options to decrease the impact of the rulemaking on their industries/sectors. We distributed outreach materials to the SERs; these materials included background, project history, CAA section 112 overview, constraints on rulemaking, affected facilities, data, rulemaking options under consideration, potential control technologies and estimated costs, applicable small entity definitions, small entities potentially subject to regulation, and questions for SERs. We met with SERs that will be impacted directly by this proposed rule to discuss the outreach materials and receive feedback on the approaches and alternatives detailed in the outreach packet. The Panel received written comments from the SERs following the meeting in response to discussions at the meeting and the questions posed to the SERs by the Agency. The SERs were specifically asked to provide comment on regulatory alternatives that could help to minimize the rule's impact on small businesses. (See elsewhere in this preamble for further information regarding the SBAR process.)

EPA consulted with state and local officials in the process of developing the proposed action to permit them to have meaningful and timely input into its development. EPA met with 10 national organizations representing state and local elected officials to provide general background on the proposal, answer questions, and solicit input from state/local governments. EPA also consulted with tribal officials early in the process of developing this proposed rule to permit them to have meaningful and timely input into its development. Consultation letters were sent to 584 tribal leaders. The letters provided information regarding EPA's development of NESHAP for EGUs and offered consultation. Three consultation meetings were requested and held. The Unfunded Mandates Reform Act (UMRA) discussion in this preamble includes a description of the consultation. (See elsewhere in this preamble for further information regarding these consultations with state, local, and tribal officials.)

XII. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under EO 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to 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.

Accordingly, EPA submitted this action to the OMB for review under EO 12866 and any changes in response to OMB recommendations have been documented in the docket for this action. For more information on the costs and benefits for this rule, please refer to Table 28 of this preamble.

When estimating the human health benefits and compliance costs in Table 28 of this preamble, EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of this rulemaking. The RIA available in the docket describes in detail the empirical basis for EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. In doing what is laid out above in this paragraph, EPA adheres to EO 13563, "Improving Regulation and Regulatory Review," (76 FR 3821, January 18, 2011), which is a supplement to EO 12866.

In addition to estimating costs and benefits, EO 13563 focuses on the importance of a "regulatory system [that] * * * promote[s] predictability and reduce[s] uncertainty" and that "identify[ies] and use[s] the best, most innovative, and least burdensome tools for achieving regulatory ends." In addition, EO 13563 states that "[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote such coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation." We recognize that the utility sector faces a variety of requirements, including ones under section 110(a)(2)(D) dealing with the interstate transport of emissions contributing to ozone and PM air quality problems, with coal combustion wastes, and with the implementation of section 316(b) of the CWA. They will also soon be the subject of a rulemaking under CAA section 111 concerning emissions of GHG. In developing today's proposed rule, EPA recognizes that it needs to endeavor to approach these rulemakings in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that underlie the rulemakings.

1. Human Health and Environmental Effects Due to Exposure to MeHg

In this section, we provide a qualitative description of human health and environmental effects due to exposure to MeHg. In 2000, the NAS Study was issued which provides a thorough review of the effects of MeHg on human health (NRC, 2000). Many of the peer-reviewed articles cited in this section are publications originally cited in the MeHg Study. In addition, EPA has conducted literature searches to obtain other related and more recent publications to complement the material summarized by the NRC in 2000.

2. Reference and Benchmark Doses

In 1995, EPA set a health-based ingestion rate for chronic oral exposure to MeHg, termed an oral RfD, at 0.0001 mg/kg-day. The RfD was based on effects reported to children exposed *in utero* during the Iraqi poisoning episode (Marsh, et al., 1987). Subsequent research from large epidemiological studies in the Seychelles, Faroe Islands, and New Zealand added substantially to the body of knowledge on neurological effects from MeHg exposure. Per Congressional direction via the House Appropriations Report for Fiscal Year 1999, the NRC was contracted by EPA to examine these data and, if appropriate, make recommendations for deriving a revised RfD. The NRC's analysis concluded that the Iraqi study on children exposed *in utero* should no longer be considered the critical study for the derivation of the RfD. NRC also provided specific recommendations to EPA for a MeHg RfD based on analyses of the three large epidemiological studies (NRC, 2000). Although derived from a more complete data set and with a somewhat different methodology, the current RfD is numerically the same as the previous (1995) RfD (0.0001 mg/kg-day).

The RfD is an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime (EPA, 2002). Data published since 2001, development of risk assessment methods, and continued examination of the concepts underlying benchmark doses and RfDs based on them add to EPA's interpretation of the 2001 MeHg RfD in the current rulemaking. Additional information on EPA's interpretation can be found in Section X of the Appropriate & Necessary TSD.

3. Neurologic Effects of Exposure to MeHg

In their review of the literature, the NRC found neurodevelopmental effects to be the most sensitive endpoints and appropriate for establishing an RfD (NRC, 2000). Studies involving animals found sensory effects and support the conclusions reached by studies involving human subjects, with a similar range of neurodevelopmental effects reported (NRC, 2000). As noted by the NRC, the clinical significance of some of the more subtle endpoints included in the human low-dose studies is difficult to gauge due to the quantal nature of the effects observed (*i.e.,* subjects either display the abnormality or do not) and the rather low occurrence rate of these effects.

Little is known about the effects of low-level chronic MeHg exposure in children that can be linked to exposures after birth. The difficulty in identifying a cohort exposed after birth but not prenatally, or separating prenatal from postnatal effects, makes research on the topic complicated. These challenges were present in the three large epidemiologic studies used to derive the RfD, as in all three studies there was postnatal exposure as well.

Several studies have shown neurological effects including delayed peak latencies in brainstem auditory evoked potentials are associated with prenatal or recent MeHg exposures (Debes, et al., 2006; Grandjean, et al., 1997; Murata, *et al.,* 2004). A recent case control study of Chinese children in Hong Kong (Cheuk and Wong, 2006) paired 59 normal controls with 52 children (younger than 18 years) diagnosed with attention deficit/hyperactivity disorder (ADHD). The authors reported a significant difference in blood Hg levels between cases and controls (geometric mean 18.2 nmol/L (95 percent confidence interval, CI, 15.4–21.5 nmol/L] vs. 11.6 nmol/L [95 percent CI 9.9–13.7 nmol/L], $p < 0.001$), which persisted after they adjusted for age, gender and parental occupational status (p less than 0.001).

Several studies have also examined the effects of chronic low-dose MeHg exposures on adult neurological and sensory functions (*e.g.,* Lebel, *et al.,* 1996; Lebel, *et al.,* 1998; Beuter and Edwards, 1998). Research results suggest that elevated hair MeHg concentrations in individuals are associated with visual deficits, including loss of peripheral vision and chromatic and contrast sensitivity. These concentrations range between a high of 50 ppm, and possibly as low as 20 ppm, although a no observed adverse effect level (NOAEL) was not clearly estimated). These individuals also exhibited a loss of manual dexterity, hand-eye coordination, and grip strength; difficulty performing complex sequences of movement; and (at the higher doses) tremors, although expression of some effects was sex-specific. Although additional data would be needed to quantify a dose-response relationship for these effects, it is noteworthy that the effects occurred at doses lower than the Japanese and Iranian poisoning episodes, via consumption of Hg-laden fish in riverine Brazilian communities. These are areas where extensive Hg contamination has resulted from small-scale gold mining activities begun in the 1980s. Note that these doses are above the EPA's RfD equivalent level for hair Hg. In regard to the Lebel, et al. (1998) study, the NRC states that "the mercury exposure of the cohort is presumed to have resulted from fish-consumption patterns that are stable and thus relevant to estimating the risk associated with chronic, low-dose MeHg exposure" (NRC, 2000). The NRC noted, however, "that the possibility cannot be excluded that the neurobehavioral deficits of the adult subjects were due to increased prenatal, rather than ongoing, MeHg exposure." More recent studies in the Brazilian communities provide some evidence that the adverse neurobehavioral effects may in fact result from postnatal exposures (*e.g.,* Yokoo, *et al.,* 2003); however, additional longitudinal study of these and other populations is required to resolve questions regarding exposure timing and fully characterize the potential neurological impacts of MeHg exposure in adults.

4. Cardiovascular Impacts of Exposure to MeHg

A number of epidemiological and toxicological studies have evaluated the relationship between MeHg exposures and various cardiovascular effects including acute myocardial infarction (AMI), oxidative stress, atherosclerosis, decreased heart rate variability (HRV), and hypertension. An AMI (*i.e.,* heart attack) is clearly an adverse health effect. The other four effects are considered "intermediary" effects and risk factors for development of AMI or coronary heart disease. Hypertension is a commonly measured clinical outcome that is also considered a risk factor for other adverse effects (such as stroke).

These epidemiological studies evaluated Hg exposures using various measures (including Hg or MeHg in blood, cord blood, hair and toenails) and the associations of these exposures with various effects. The overall results of the available studies (published before and after NRC 2000) are summarized in the following paragraphs.

Studies in two cohorts (the Kuopio Ischemic Heart Disease Risk Factor study, or KIHD study; and the European Community Multicenter Study on Antioxidants, Myocardial Infarction and Breast Cancer, or EURAMIC study), report statistically significant positive associations between MeHg exposure and AMI. A third study (U.S. Health Professionals Study, USHPS) also reported a positive association between Hg exposure and AMI but only after excluding individuals who may have been occupationally exposed to inorganic Hg. However, a fourth study (the Northern Sweden Health and Disease Study, or NSHDS) reported an inverse relationship between MeHg exposure and AMI, and another study (Minamata Cohort) identified no increase in fatal heart attacks following a MeHg poisoning epidemic.

Although each of these AMI studies had strengths and limitations, the EURAMIC and KIHD studies appear to be most robust. Strengths of these two studies include their large sample sizes and control for key potential confounders (such as exposure to omega-3 fatty acid, which are related to decreases in cardiovascular effects). The KIHD study was well-designed and included a population-based recruitment and limited loss to follow-up. Additional strengths of the EURAMIC study include exposure data that were collected shortly after the AMI. In addition, recruitment of participants across nine countries likely resulted in a wide range of MeHg and fish fatty acid intakes. Although the USHPS study was well-conducted, the Hg exposure measure used was potentially confounded by possible inorganic Hg exposures in roughly half of the study population. When these subjects were excluded from the analyses, the power of the study to detect an effect was reduced. Limitations of the NSHDS study included its relatively small sample size and narrow MeHg exposure range. The Minamata study also had important limitations, primarily that the effects of the very high exposures in this population may differ substantially from effects of lower exposures expected at typical environmental levels; also the death certificates were collected starting 10 years after the initial cases of MeHg poisoning.

In summary, the most robust available studies (*i.e.,* the EURAMIC and KIHD), report statistically significant positive relationships between MeHg exposure and the incidence of AMI. Further, both studies report statistically significantly positive trend tests for the relationship between MeHg and AMI. The USHPS provides some additional evidence of a positive association. The NSHDS and the Minamata Cohort studies are less robust; however, the results from those two studies showed no adverse effect, and, therefore, reduce the overall confidence in the association of MeHg with AMIs.

The studies that evaluated intermediary effects generally provide some additional evidence of the potential adverse effects of Hg or MeHg to the cardiovascular system. However, results are somewhat inconsistent. For example, two epidemiological studies (the KIHD and the Tapajós River Basin studies) reported positive associations between MeHg exposures and oxidative stress, but one short-term study (the Quebec Sport Fisherman Study) reported a negative association. For atherosclerosis, the results across epidemiological studies are more consistent. Three studies (the KIHD, Faroese Whaler Cohort Study, and Nunavik Inuit Cohort in Quebec) reported a positive association between MeHg exposure and atherosclerosis. Moreover, animal studies and *in vitro* studies (cell studies) provide additional evidence that MeHg may cause oxidative stress and increased risk of atherosclerosis.

Another intermediary effect, decreases in heart rate variability (HRV), can be indicative of cardiovascular disease, particularly in the elderly. Associations of decreased HRV with increased MeHg exposures have been reported in four of five studies of adults and three studies of children; however, the clinical significance of decreased HRV in children is not known.

The existing epidemiological studies are inconsistent in showing an association between MeHg and hypertension. A prospective study of the Faroe Islands birth cohort reported statistically significant associations between elevated cord blood Hg levels or maternal hair Hg levels and increased diastolic and systolic blood pressures for 7-year-old children; this association was no longer seen in the children tested at 14 years. Other studies suggest that these are not correlated.

In January 2010, EPA sponsored a workshop in which a group of experts were asked to assess the plausibility of a causal relationship between MeHg exposure and cardiovascular health effects, and to advise EPA on methodologies for estimating population-level cardiovascular health impacts of reduced MeHg exposure. The final workshop report was published in January, 2011, and includes as its key recommendation the development of a dose-response function relating MeHg exposure and AMI incidence for use in regulatory benefits analyses that target Hg air emissions.

The experts identified both intermediary and clinical effects in the published literature. The panelists assessed the strength of evidence associated with three intermediary effects (*i.e.,* oxidative stress, atherosclerosis, and HRV), and with two main clinical effects (*i.e.,* hypertension and AMI). The panel concluded there was at least moderate evidence of an association between MeHg exposure and all of these effects in the epidemiological literature. The evidence for an association with hypertension was considered the weakest.

The workshop panel concluded that "a causal link between MeHg and AMI is plausible, given the range of intermediary effects for which some positive evidence exists and the strength and consistency across the epidemiological studies for AMI.” During the workshop, the individual experts provided quantitative estimates of the likelihood of a true causal relationship between MeHg and AMI, ranging from 0.45 to 0.80, and characterized by the panel as “moderate to strong.” A recently published health benefits analysis of reduced MeHg exposures analyzed the epidemiology literature and assessed the “plausibility of causal interpretation of cardiovascular risk” as about ⅓ as a separate parameter in their analysis.

EPA did not develop a quantitative dose-response assessment or quantified estimates of benefits for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail Hg levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

5. Genotoxic Effects of Exposure to MeHg

The Mercury Study noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NRC concluded that evidence that human exposure to MeHg caused genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders.) One study of adults living in the Tapajós River region in Brazil (Amorim, et al., 2000) reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes,; polyploidal aberrations and chromatid breaks observed at Hg hair levels around 7.25 ppm and 10 ppm, respectively. Long-term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary, chronic MeHg exposures similar to and above those seen in the Faroes and Seychelles populations.

6. Immunotoxic Effects to Exposure to MeHg

Although exposure to some forms of Hg can result in a decrease in immune activity or an autoimmune response (ATSDR, 1999), evidence for immunotoxic effects of MeHg is limited (NRC, 2000). Some persistent immunotoxic effects have been observed in mice treated with MeHg in drinking water at relatively high levels of exposure (Havarinasab, *et al.,* 2007). A recent study of fish-consuming communities in Amazonian Brazil has identified a possible association between MeHg exposure and immunotoxic effects reflective of autoimmune dysfunction. The authors noted that this may reflect interactions with infectious disease and other factors (Silva, *et al.,* 2004). Exposures to these communities occurred via fish consumption (some community members were also exposed to inorganic Hg through gold mining activities). The researchers assessed levels of specific antibodies that are markers of Hg-induced autoimmunity. They found that both prevalence and levels of these antibodies were higher in a population exposed to MeHg via fish consumption compared to a reference (unexposed) population. Median hair Hg concentration was 8 ppm in the more exposed population (range 0.29 to 58.47 ppm) and 5.57 ppm in the less exposed reference population (range 1.19 to 16.96 ppm). The ranges of Hg hair concentrations reported in this study are within an order of magnitude of the concentration corresponding to the MeHg RfD. Overall, there is a relatively small body of evidence from human studies that suggests exposure to MeHg can result in immunotoxic effects.

7. Other Hg-Related Human Toxicity Data

Based on limited human and animal data, MeHg is classified as a “possible” human carcinogen by the IARC (1994) and in the IRIS (EPA, 2002). The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between Hg exposure and overall cancer incidence, although a few studies have shown an association between Hg exposure and specific types of cancer incidence (*e.g.,* acute leukemia and liver cancer; NRC, 2000). The Mercury Study observed that “MeHg is not likely to be a human carcinogen under conditions of exposure generally encountered in the environment” (p 6–16, Vol. V). This was based on observation that tumors were noted in one species only at doses causing severe toxicity to the target organ. Although some of the human and animal research suggests that a link between MeHg and cancer may plausibly exist, more research is needed.

There is also some evidence of reproductive and renal toxicity in humans from MeHg exposure. For example, a smaller than expected number of pregnancies were observed among women exposed via contaminated wheat in the Iraqi poisoning episode of 1956 (Bakir, *et al.,* 1973); other victims of that same poisoning event exhibited signs of renal damage (Jalili and Abbasi, 1961); and an increased incidence of deaths due to kidney disease was observed in women exposed in Minamata Bay via contaminated fish (Tamashiro, *et al.,* 1986). Other data from animal studies suggest a link between MeHg exposure and similar reproductive and renal effects, as well as hematological toxicity (NRC, 2000). Overall, human data regarding reproductive, renal, and hematological toxicity from MeHg are very limited and are based on either studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis. Note that the Mercury Study provides an assessment of MeHg cancer risk using the 1993 version of the Revised Cancer Guidelines.

8. Ecological Effects of Hg

Deposition of Hg to watersheds can also have an impact on ecosystems and wildlife. Mercury contamination is present in all environmental media with aquatic systems experiencing the greatest exposures due to bioaccumulation. Bioaccumulation refers to the net uptake of a contaminant from all possible pathways and includes the accumulation that may occur by direct exposure to contaminated media as well as uptake from food. In the sections that follow, numerous adverse effects have been identified. Further reducing the presence of Hg in the environment may help to alleviate the potential for adverse ecological health outcomes.

A review of the literature on effects of Hg on fish[188] reports results for numerous species including trout, bass (large and smallmouth), northern pike, carp, walleye, salmon, and others from

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[188] Crump, KL, and Trudeau, VL. Mercury-induced reproductive impairment in fish. Environmental Toxicology and Chemistry. Vol. 28, No. 5, 2009.

laboratory and field studies. The studies were conducted in areas from New York to Washington and the effects studied are reproductive in nature. Although we cannot determine at this time whether these reproductive deficits are affecting fish populations across the U.S. it should be noted that it would seem reasonable that over time reproductive deficits would have an effect on populations. Lower fish populations would conceivably impact the ecosystem services like recreational fishing derived from having healthy aquatic ecosystems.

Mercury also affects avian species. In previous reports [189] much of the focus has been on large piscivorous species in particular the common loon. The loon is most visible to the public during the summer breeding season on northern lakes and they have become an important symbol of wilderness in these areas.[190] A multitude of loon watch, preservation, and protection groups have formed over the past few decades and have been instrumental in promoting conservation, education, monitoring, and research of breeding loons.[191] Significant adverse effects on breeding loons from Hg have been found to occur including behavioral (reduced nest-sitting), physiological (flight feather asymmetry) and reproductive (chicks fledged/territorial pair) effects and reduced survival.[192] Additionally, Evers, et al. (see footnote 5), report that they believe that the weight of evidence indicates that population-level effects occur in parts of Maine and New Hampshire, and potentially in broad areas of the loon's range.

Recently attention has turned to other piscivorous species such as the white ibis, and great snowy egret. Although considered to be fish-eating generally, these wading birds have a very wide diet including crayfish, crabs, snails, insects and frogs. These species are experiencing a range of adverse effects due to exposure to Hg. The white ibis has been observed to have decreased foraging efficiency.[193] Additionally ibises have been shown to exhibit decreased reproductive success and altered pair behavior.[194] These effects include significantly more unproductive nests, male/male pairing, reduced courtship behavior and lower nestling production by exposed males. In this study, a worst-case scenario suggested by the results could involve up to a 50 percent reduction in fledglings due to MeHg in diet. In egrets, Hg has been implicated in the decline of the species in south Florida [195] and Hoffman [196] has shown that egrets show liver and possibly kidney effects. Although ibises and egrets are most abundant in coastal areas and these studies were conducted in south Florida and Nevada the ranges of ibises and egrets extend to a large portion of the U.S.

Insectivorous birds have also been shown to suffer adverse effects due to Hg exposure. These songbirds such as Bicknell's thrush, tree swallows, and the great tit have shown reduced reproduction, survival, and changes in singing behavior. Exposed tree swallows produced fewer fledglings,[197] lower survival,[198] and had compromised immune competence.[199] The great tit has exhibited reduced singing behavior and smaller song repertoire in areas of high contamination.[200] These effects may result in population reductions sufficient to affect people's enjoyment of these birds.

In mammals adverse effects have been observed in mink and river otter, both fish eating species. For otter from Maine and Vermont, maximum concentrations on Hg in fur nearly equal or exceed a concentration associated with mortality and concentration in liver for mink in Massachusetts/Connecticut and the levels in fur from mink in Maine exceed concentrations associated with acute mortality.[201] Adverse sublethal effects may be associated with lower Hg concentrations and consequently be more widespread than potential acute effects. These effects may include increased activity, poorer maze performance, abnormal startle reflex, and impaired escape and avoidance behavior.[202] Although we do not have data to show population level effects that would impact wildlife viewing and enjoyment these are ecosystem services potentially affected by impacts on these species.

The proposed rule will also reduce emissions of directly emitted PM and ozone precursors and estimates of the PM$_{2.5}$-related co-benefits of these air quality improvements may be found in Table 28 of this preamble. When characterizing uncertainty in the PM-mortality relationship, EPA has historically presented a sensitivity analysis applying alternate assumed thresholds in the PM concentration-response relationship. In its synthesis of the current state of the PM science, EPA's 2009 Integrated Science Assessment for Particulate Matter concluded that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship. In the RIA accompanying this rulemaking, rather than segmenting

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[192] Evers, DC, Savoy, LJ, DeSorbo, CR, Yates, DE, Hanson, W, Taylor, KM, Siegel, LS, Cooley, JH, Jr., Bank, MS, Major, A, Munney, K, Mower, BF, Vogel, HS, Schoch, N, Pokras, M, Goodale, MW, Fair, J. Adverse effects from environmental mercury loads on breeding common loons. Ecotoxicology. 17:69–81, 2008; Mitro, MG, Evers, DC, Meyer, MW, and Piper, WH. Common loon survival rates and mercury in New England and Wisconsin. Journal of Wildlife Management. 72(3): 665–673, 2008.

[193] Adams, EM, and Frederick, PC. Effects of methylmercury and spatial complexity on foraging behavior and foraging efficiency in juvenile white ibises (Eudocimus albus). Environmental Toxicology and Chemistry. Vol 27, No. 8, 2008.

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[196] Hoffman, DJ, Henny, CJ, Hill, EF, Grover, RA, Kaiser, JL, Stebbins, KR. Mercury and drought along the lower Carson River, Nevada: III. Effects on blood and organ biochemistry and histopathology of snowy egrets and black-crowned night-herons on Lahontan Reservoir, 2002–2006. Journal of Toxicology and Environmental Health, Part A. 72: 20, 1223–1241, 2009.

[197] Brasso, RL, and Cristol, DA. Effects of mercury exposure in the reproductive success of tree swallows (Tachycineta bicolor). Ecotoxicology. 17:133–141, 2008.

[198] Hallinger, KK, Cornell, KL, Brasso, RL, and Cristol, DA. Mercury exposure and survival in free-living tree swallows (Tachycineta bicolor). Ecotoxicology. Doi: 10.1007/s10646–010–0554–4, 2010.

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[202] Scheuhammer, AM, Meyer MW, Sandheinrich, MB, and Murray, MW. Effects of environmental methylmercury on the health of wild birds, mammals, and fish. Ambio. Vol. 36, No. 1, 2007.

out impacts predicted to be associated levels above and below a “bright line” threshold, EPA includes a “lowest measured level” (LML) analysis that illustrates the increasing uncertainty that characterizes exposure attributed to levels of $PM_{2.5}$ below the LML of each epidemiological study used to estimate $PM_{2.5}$-related premature death. Figures provided in the RIA show the distribution of baseline exposure to $PM_{2.5,}$ as well as the lowest air quality levels measured in each of the epidemiology cohort studies. This information provides a context for considering the likely portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the size of the estimated reduction $PM_{2.5}$-related premature mortality diminishes as baseline concentrations of $PM_{2.5}$ are lowered. Using the Pope, *et al.* (2002) study, 86 percent of the population is exposed at or above the LML of 7.5 µg/m^3. Using the Laden, *et al.* (2006) study, 30 percent of the population is exposed at or above the LML of 10 µg/m^3. Although the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Benefits are shown as a range from Pope, et al., (2002) to Laden, *et al.,* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type.

The cost analysis is also subject to uncertainties. Estimating the cost conversion from one process to another is more difficult than estimating the cost of adding control equipment because it is more dependent on plant specific information. More information on the cost uncertainties can be found in the RIA.

A summary of the monetized benefits and net benefits for the proposed rule at discount rates of 3 percent and 7 percent is in Table 28 of this preamble.

For more information on the benefits analysis, please refer to the RIA for this rulemaking, which is available in the docket.

B. Paperwork Reduction Act

The information collection requirements in this proposed rule will be submitted for approval to the OMB under the PRA, 44 U.S.C. 3501 *et seq.* An ICR document has been prepared by EPA (ICR No. 2137.05).

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 CAA section 114 (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.

This proposed rule would require maintenance inspections of the control devices but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $49.1 million. This includes 329,605 labor hours per year at a total labor cost of $27.0 million per year, and total non-labor capital costs of $22.1 million per year. This estimate includes initial and annual performance test, conducting and documenting a tune-up, semiannual excess emission reports, maintenance inspections, developing a monitoring plan, notifications, and recordkeeping. The total burden for the Federal government (averaged over the first 3 years after the effective date of the standard) is estimated to be 18,039 hours per year at a total labor cost of $877 million per year.

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 our regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

To comment on EPA'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 EPA–HQ–OAR–2009–0234. Submit any comments related to the ICR to EPA and OMB. *See* **ADDRESSES** section at the beginning of this preamble 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 May 3, 2011, a comment to OMB is best assured of having its full effect if OMB receives it by June 2, 2011. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act (RFA), as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 et seq.

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's proposed rule on small entities, small entity is defined as (as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201): (1) A small business according to SBA size standards by the North American Industry Classification System category of the owning entity (for NAICS 221112 and 221122, the range of small business size standards for electric utilities is 4 million megawatt hours of production or less); (2) a small governmental jurisdiction that is a government of a city, county, town, township, village, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed rule on small entities, EPA cannot certify that this action will not have a significant economic impact on a substantial number of small entities. This determination, which is included in the Initial Regulatory Flexibility Analysis (IRFA) found in Chapter 10 of the RIA for this proposed rule, is based on the economic impact of this proposed rule to all affected small entities across the electric power sector.

The summary of the IRFA is as follows. EPA has assessed the potential impact of this action on small entities and found that approximately 102 of the estimated 1,400 EGUs potentially affected by today's proposed rule are owned by the 83 potentially affected small entities identified by EPA's analysis. EPA estimates that 59 of the 83 identified small entities will have annualized costs greater than 1 percent of their revenues.

Because the potential existed for a likely significant impact for substantial number of small entities, EPA convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of this rule.

1. Panel Process and Panel Outreach

As required by RFA section 609(b), as amended by SBREFA, EPA has conducted outreach to small entities and on October 27, 2010, EPA's Small Business Advocacy Chairperson convened a Panel under RFA section 609(b). In addition to the Chair, the Panel consisted of the Director of the Sector Policies and Programs Division within EPA's Office of Air and Radiation, the Chief Counsel for Advocacy of SBA, and the Administrator of the Office of Information and Regulatory Affairs within OMB.

As part of the SBAR Panel process we conducted outreach with representatives from 18 various small entities that potentially would be affected by this rule. The SERs included representatives of EGUs owned by municipalities, cooperatives, and private investors. We distributed outreach materials to the SERs; these materials included background and project history, CAA section 112 overview, constraints on the rulemaking, rulemaking options under consideration, and potential control technologies and estimated cost. We met with 14 of the SERs, as well as five non-SER participants from organizations representing power producers, on December 2, 2010, to discuss the outreach materials, potential requirements of the rule, and regulatory areas where EPA has discretion and could potentially provide flexibility. The Panel received written comments from, or on behalf of, 10 SERs following the meeting in response to discussions at the meeting and the questions posed to the SERs by the Agency. The SERs were specifically asked to provide comment on regulatory approaches that could help to minimize the rule's impact on small businesses.

2. Panel Recommendations for Small Business Flexibilities

Consistent with the RFA/SBREFA requirements, the Panel evaluated the assembled materials and small-entity comments on issues related to elements of the IRFA. A copy of the Final Panel Report (including all comments received from SERs in response to the Panel's outreach meeting) is included in the docket for this proposed rule. In general, the Panel recommended that EPA consider its various flexibilities to the maximum extent possible consistent with CAA requirements to mitigate the impacts of the rulemaking on small businesses and to seek comment on potential adverse economic impacts of the proposed rule on affected small entities and recommendations to mitigate such impacts. With respect to specific issues and options, however, there were varying recommendations from panel members. Issues and options discussed among the panel members included: (1) MACT floor determinations and variability assessment; (2) monitoring, reporting, and recordkeeping requirements; (3) subcategorization; (4) area source standards; (5) work practice standards; (6) health based emission limits; (7) related Federal rules; (8) potential adverse economic impacts; and (9) concerns with the SBAR process. Panel member recommendations regarding each of these issues and options are presented in Chapter 9 of the Final Panel Report. As noted elsewhere in this preamble, this proposal is based on a regulatory alternative that includes subcategorization, MACT floor-based numerical emission limitations, work practice standards, alternative standards, alternative compliance options, and emissions averaging.

We invite comments on all aspects of the proposal and its impacts, including potential adverse impacts, on small entities.

D. Unfunded Mandates Reform Act of 1995

Title II of the UMRA of 1995, Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Under UMRA section 202, 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, UMRA section 205 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 UMRA section 205 do not apply when they are inconsistent with applicable law. Moreover, UMRA 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 UMRA section 203. 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 this 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 entitled "Unfunded Mandates Reform Act Analysis for the Proposed Toxics Rule" under UMRA section 202 that is within the RIA and which is summarized below.

1. Statutory Authority

As discussed elsewhere in this preamble, the statutory authority for this proposed rulemaking is CAA section 112. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. CAA section 112(b) 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.

CAA section 112(d) 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 coal- and oil-fired EGUs.

In compliance with UMRA section 205(a), 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 RIA for this rulemaking and in the docket. The regulatory alternative upon which this proposed rule is based represents the MACT floor for all regulated pollutants for four of the five subcategories of EGUs and for all but one regulated pollutant for the fifth subcategory. These proposed MACT floor-based standards represent the least costly and least burdensome alternative. Beyond-the-floor emission limits for Hg are proposed for existing and new EGUs designed to burn coal having a calorific value less than 8,300 Btu/lb.

2. Social Costs and Benefits

The RIA prepared for this proposed rule including the Agency's assessment of costs and benefits and is in the docket.

It is estimated that 3 years after implementation of this proposed rule, HAP would be reduced by thousands of tons, including reductions in HCl, HF, metallic HAP (including Hg), and several other organic HAP from EGUs. Studies have determined a relationship between exposure to these HAP and the onset of cancer; however, the Agency is unable to provide a monetized estimate of the HAP benefits at this time. In addition, there are significant reductions in $PM_{2.5}$ and in SO_2 that would occur, including approximately 84 thousand tons of $PM_{2.5}$ and over 2 million tons of SO_2. These reductions occur by 2016 and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) is a reduction in premature mortality. Other health effects associated with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks, and work-lost days *(i.e.,* days when employees are unable to work). Although we are unable to monetize the benefits associated with the HAP emissions reductions other than for Hg, we are able to monetize the benefits associated with the $PM_{2.5}$ and SO_2 emissions reductions. For SO_2 and $PM_{2.5}$, we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2016 associated with the implementation of the proposed alternative range from $59 billion (2007 dollars) to $140 billion (2007 dollars) when using a 3 percent discount rate (or from $53 billion (2007 dollars) to $130 billion (2007 dollars) when using a 7 percent discount rate). Our estimate of social costs is $10.9 billion (2007 dollars). For more detailed information on the benefits and costs estimated for this proposed rulemaking, refer to the RIA in the docket.

3. Future and Disproportionate Costs

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

EPA assessed the economic and financial impacts of the rule on government-owned entities using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent of base revenues. EPA projects that 55 government entities will have compliance costs greater than 1 percent of base generation revenue in 2016, and 37 may experience compliance costs greater than 3 percent of base revenues. Also, one government entity is estimated to have all of its affected units retire. Overall, 17 units owned by government entities retire. It is also worth noting that two-thirds of the net compliance costs shown above are due to lost profits from retirements. More than half of those lost profits arise from retiring two large units, according to EPA modeling. For more details on these results and the methodology behind their estimation, see the results included in the RIA and which are discussed previously in this preamble.

4. Effects on the National Economy

UMRA requires that we estimate the effect of this 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 this proposed rule is presented in the RIA in the docket. This analysis provides estimates of the effect of this proposed rule on some of the categories mentioned above. The results of the economic impact analysis are summarized previously in this preamble. The results show that there will be a less than 4 percent increase in electricity price on average nationwide in 2016, and a less than 7 percent increase in natural gas price nationwide in 2016. Power generation from coal-fired plants will fall by about 1 percent nationwide in 2016.

5. Consultation With Government

UMRA 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, UMRA section 203 requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a proposal. Consistent with the intergovernmental consultation provisions of UMRA section 204, EPA has initiated consultations with governmental entities affected by this proposed rule. EPA invited the following 10 national organizations representing state and local elected officials to a meeting held on October 27, 2010, in Washington DC: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations of elected state and local officials have been identified by EPA as the "Big 10" organizations appropriate to contact for purpose of consultation with elected officials. The purposes of the consultation were to provide general background on the proposal, answer questions, and solicit input from State/local governments. During the meeting, officials asked clarifying questions regarding CAA section 112 requirements and central decision points presented by EPA (*e.g.,* use of surrogate pollutants to address HAP, subcategorization of source category, assessment of emissions variability). They also expressed uncertainty with regard to how utility boilers owned/operated by state and local entities would be impacted, as well as with regard to the potential burden associated with implementing the rule on state and local entities (*i.e.,* burden to re-permit affected EGUs or update existing permits). Officials requested, and EPA provided, addresses associated with the 112 state and local governments estimated to be potentially impacted by the proposed rule. EPA has not received additional questions or requests from state or local officials.

Consistent with UMRA section 205, EPA has identified and considered a reasonable number of regulatory alternatives. Because the potential existed for a likely significant impact for substantial number of small entities, EPA convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of the rule. As part of that process, EPA considered several options. Those options included establishing emission limits, establishing work practice standards, establishing subcategories, and consideration of monitoring options. The regulatory alternative selected is a combination of the options considered and includes proposed provisions regarding a number of the recommendations resulting from the SBAR Panel process as described below (see elsewhere in this preamble for more detail).

EPA determined that there is a distinguishable difference in emissions characteristics associated with five EGU design types and that these characteristics may affect the feasibility and/or effectiveness of emission control. Thus, the five types of units are proposed to be regulated separately (*i.e.,* subcategorized) to account for the difference in emissions and applicable controls. The proposal establishes three subcategories for coal-fired EGUs and two subcategories for oil-fired EGUs: (1) Coal-fired units designed to burn coal having a calorific value of 8,300 Btu/lb or greater, (2) coal-fired units designed to burn virgin coal having a calorific value less than 8,300 Btu/lb, (3) IGCC units (for Hg emissions only), (4) liquid oil units, and (5) solid oil-derived units.

The regulatory alternative upon which the proposed standards for coal-fired EGUs are based includes: (1) MACT floor-based numerical emission limitations for HCl (a HAP as well as a surrogate for all other acid gas HAP) and for PM (a surrogate for non-Hg metallic HAP) for existing and new EGUs in all three subcategories; (2) MACT floor-based numerical emission limitations for Hg for existing and new coal-fired units designed to burn coal having a calorific value of 8,300 Btu/lb or greater and IGCC units; (3) beyond-the-floor numerical emission limitations for Hg for existing and new coal-fired units designed to burn virgin coal having a calorific value less than 8,300 Btu/lb; and (4) work practices to limit emissions of dioxin/furan organic HAP and non-dioxin/furan organic HAP for existing and new EGUs in all three subcategories. The regulatory alternative upon which the proposed standards for oil-fired EGUs are based includes: (1) MACT floor-based numerical emission limitations for Hg, total non-Hg metallic HAP, HCl, and HF for existing and new EGUs in both subcategories; and (2) work practices to limit emissions of dioxin/furan organic HAP and non-dioxin/furan organic HAP for existing and new EGUs in both subcategories. The proposed use of surrogate pollutants would result in reduced compliance costs because testing would only be required for the surrogate pollutants (*i.e.,* HCl and PM) versus for the HAP (*i.e.,* acid gases and non-Hg metals).

EPA also is proposing three alternative standards for certain subcategories: (1) SO_2 (as an alternate to HCl for all subcategories with add-on FGD systems except IGCC units and liquid oil-fired units); (2) individual non-Hg metallic HAP (as an alternate to PM for all subcategories except liquid oil-fired units, and as an alternative to total non-Hg metallic HAP for the liquid oil-fired units subcategory); and (3) total non-Hg metallic HAP (as an alternate to PM for all subcategories except liquid oil-fired units). In addition, liquid oil-fired EGUs may choose to demonstrate compliance with the Hg, non-Hg metallic HAP, HCl, and HF emission limits on the basis of fuel analysis. Maximum fuel inlet values for Hg, non-Hg metals, chlorine, and fluorine would be established based on the inlet fuel values measured during the performance test indicating compliance with the emission limits. We also are proposing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for units at the affected source that are within a single subcategory. Alternative standards, alternative compliance options, and emissions averaging can provide sources the flexibility to comply in the least costly manner.

The proposed work practice standard, which requires implementation of an annual performance (compliance) test program includes requirements to inspect the burner, flame pattern, and the system controlling the air-to-fuel ratio, and make any necessary adjustments and/or conduct any required maintenance and repairs; minimize CO emissions consistent with the manufacturer's specifications; measure the concentration of CO in the effluent stream before and after any adjustments are made; and submit an annual report containing the concentrations of CO and O_2 measured before and after adjustments, a description of any corrective actions taken as a part of the combustion adjustment, and the type and amount of fuel used over the 12 months prior to the annual adjustment.

E. Executive Order 13132, Federalism

Under EO 13132, EPA may not issue an action that has federalism 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 state and local governments, or EPA consults with state and local officials early in the process of developing the proposed action.

EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the Federal government will not provide the funds necessary to pay those costs. Accordingly, EPA provides the following federalism summary impact statement as required by section 6(b) of EO 13132.

Based on the estimates in EPA's RIA for today's proposed rule, the proposed regulatory option, if promulgated, may have federalism implications because the option may impose approximately $666.3 million in annual direct compliance costs on an estimated 97 state or local governments. Specifically, we estimate that there are 81 municipalities, 5 states, and 11 political subdivisions (*i.e.,* a public district with territorial boundaries embracing an area wider than a single municipality and frequently covering more than one county for the purpose of generating, transmitting and distributing electric energy) that may be directly impacted by today's proposed rule. Responses to EPA's 2010 ICR were used to estimate the nationwide number of potentially impacted state or local governments. As previously explained, this 2010 survey was submitted to all coal- and oil-fired EGUs listed in the 2007 version of DOE/EIA's "Annual Electric Generator Report," and "Power Plant Operations Report."

EPA consulted with state and local officials in the process of developing the proposed rule to permit them to have meaningful and timely input into its development. EPA met with 10 national organizations representing state and local elected officials to provide general background on the proposal, answer questions, and solicit input from *state*/local governments. The UMRA discussion in this preamble includes a description of the consultation.

In the spirit of EO 13132, and consistent with EPA policy to promote communications between EPA and state and local governments, EPA specifically solicits comment on this proposed action from state and local officials.

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

Subject to EO 13175 (65 FR 67249, November 9, 2000) 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 and develops a tribal summary impact statement. Executive Order 13175 requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications."

EPA has concluded that this action may have tribal implications. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt tribal law. This proposed rule would impose requirements on owners and operators of EGUs. EPA is aware of three coal-fired EGUs located in Indian Country but is not aware of any EGUs owned or operated by tribal entities.

EPA offered consultation with tribal officials early in the process of developing this proposed regulation to permit them to have meaningful and timely input into its development. Consultation letters were sent to 584 tribal leaders. The letters provided information regarding EPA's development of NESHAP for EGUs and offered consultation. Three consultation meetings were held on December 7, 2010, with the Upper Sioux Community of Minnesota; on December 13 with Moapa Band of Paiutes, Forest County Potawatomi, Standing Rock Sioux Tribal Council, Fond du Lac Band of Chippewa; and on January 5, 2011 with the Forest County Potawatomi, and a representative from the National Tribal Air Association (NTAA). In these meetings, EPA presented the authority under the CAA used to develop these rules, and an overview of the industry and the industrial processes that have the potential for regulation. Tribes expressed concerns about the impact of EGUs on the reservations. Particularly, they were concerned about potential Hg deposition and the impact on the water resources of the Tribes, with particular concern about the impact on subsistence lifestyles for fishing communities, the cultural impact of impaired water quality for ceremonial purposes, and the economic impact on tourism. In light of these concerns, the tribes expressed interest in an expedited implementation of the rule, they expressed concerns about how the Agency would consider variability in setting the standards and use tribal-specific fish consumption data from the tribes in our assessments, they were not supportive of using work practice standards as part of the rule, and they asked the Agency to consider going beyond-the-floor to offer more protection for the tribal communities. A more specific list of comments can be found in the Docket.

In addition to these consultations, EPA also conducted outreach on this rule through presentations at the National Tribal Forum in Milwaukee, WI, and on NTAA calls. EPA specifically requested tribal data that could support the appropriate and necessary analysis and the RIA for this rule. We will also hold additional meetings with tribal environmental staff to inform them of the content of this proposal as well as provide additional consultation with tribal elected officials where it is appropriate.

EPA specifically solicits additional comment on this proposed rule from tribal officials.

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

Executive Order 13045 (62 FR 19,885, April 23, 1997) applies to any rule that: (1) Is determined to be "economically significant" as defined under EO 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of this planned rule on children, and explain why this planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This proposed rule is subject to EO 13045 because it is an economically significant regulatory action as defined by EO 12866, and we believe that the action concerns an environmental health risk which may have a disproportionate impact on children. Although this proposed rule is based on technology performance, the statute is designed to require standards that are likely to protect against hazards to public health with an adequate margin of safety as described elsewhere in this document. The protection offered by this proposed rule is especially important for children, especially the developing fetus. As referenced in the section entitled, "Consideration of Health Risks to Children and Environmental Justice Communities" children are more vulnerable than adults to many HAP emitted by EGUs due to differential behavior patterns and physiology. These unique susceptibilities were carefully considered in a number of different ways in the analyses associated with this rulemaking, and are summarized elsewhere in this document.

The public is invited to submit comments or identify peer-reviewed studies and data that assess effects of early life exposure to this proposed rule.

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

We estimate a less than 4 percent price increase for electricity nationwide in 2016 and a 1 percent percentage fall in coal-fired power production. EPA projects that delivered natural gas prices will increase by about 1 percent over the 2015 to 2030 timeframe. For more information on the estimated energy effects, please refer to the economic impact analysis for this proposed rule. The analysis is available in the RIA, which is in the public docket.

Therefore, we conclude that this proposed rule when implemented is likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

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

This rulemaking involves technical standards. EPA cites the following standards in this proposed rule: EPA Methods 1, 2, 2F, 2G, 3A, 3B, 4, 5, 5D, 6, 6C, 9, 19, 26, 26A, 29, 30A, 30B, and 202 of 40 CFR part 60. Consistent with the NTTAA, EPA conducted searches to identify VCS in addition to these EPA methods. No applicable voluntary standards were identified for EPA Methods 2F, 2G, 8, 19, 201A, and 202. The search and review results have been documented and are placed in the docket for this proposed rule.

EPA has decided to use American National Standards Institute (ANSI)/ASME PTC 19–10–1981 Part 10, "Flue and Exhaust Gas Analyses," acceptable as an alternative to Methods 3B (for CO_2, CO, and O_2), 6 (for SO_2), 6A and 6B (for CO_2 and SO_2). This standard is available from the ASME, Three Park Avenue, New York, NY 10016–5990.

Another VCS, ASTM D6735–01, "Standard Test Method for Measurement of Gaseous Chlorides and Fluorides from Mineral Calcining Exhaust Sources Impinger Method," is an acceptable alternative to EPA Methods 26 and 26A.

An additional VCS, ASTM D6784–02 (2008)—Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method) is acceptable as an alternative to Method 29 for Hg, but only if the standard falls within the applicable concentration range of 0.5 to 100 $\mu g/Nm^3$.

During the search, if the title or abstract (if provided) of the VCS described technical sampling and analytical procedures that are similar to EPA's reference method, EPA ordered a copy of the standard and reviewed it as a potential equivalent method. All potential standards were reviewed to determine the practicality of the VCS for this rule. This review requires significant method validation data which meets the requirements of EPA Method 301 for accepting alternative methods or scientific, engineering and policy equivalence to procedures in EPA reference methods. EPA may reconsider determinations of impracticality when additional information is available for particular VCS.

The search identified 22 other VCS that were potentially applicable for this rule in lieu of EPA reference methods. After reviewing the available standards, EPA determined that 22 candidate VCS (ASTM D3154–00 (2006), ASME B133.9–1994 (2001), ANSI/ASME PTC 19–10–1981 Part 10, ASTM D5835–95 (2007), International Organization for Standards (ISO) 10396:1993 (2007), ISO 12039:2001, ASTM D6522–00 (2005), Canadian Standards Association (CAN/CSA) Z223.2–M86 (1999), ISO 9096:1992 (2003), ANSI/ASME PTC–38–1980 (1985), ASTM D3685/D3685M–98 (2005), ISO 7934:1998, ISO 11632:1998, ASTM D3464–96 (2007), ASTM D3796–90 (2004), ISO 10780:1994, CAN/CSA Z223.21–M1978, ASTM D3162–94 (2005), CAN/CSA Z223.1–M1977, EN 1911–1,2,3 (1998), EN 13211:2001, CAN/CSA Z223.26–M1987) identified for measuring emissions of pollutants or their surrogates subject to emission standards in the proposed rule would not be practical due to lack of equivalency, documentation, validation data, and other important technical and policy considerations. These 22 methods are listed Attachment 1 to the documentation memo, along with the EPA review comments, which may be found in the docket.

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

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on EJ. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations, low-income, and tribal populations in the U.S.

This proposed rule establishes national emission standards for new and existing EGUs that combust coal and oil. EPA estimates that there are approximately 1,400 units located at 550 facilities covered by this proposed rule.

This proposed rule will reduce emissions of all the listed HAP that come from EGUs. This includes metals (Hg, As, Be, Cd, Cr, Pb, Mn, Ni, and Se), organics (POM, acetaldehyde, acrolein, benzene, dioxins, ethylene dichloride, formaldehyde, and PCB), and acid gases (HCl and HF). At sufficient levels of exposure, these pollutants can cause a range of health effects including cancer; irritation of the lungs, skin, and mucous membranes; effects on the central nervous system such as memory and IQ loss and learning disabilities; damage to the kidneys; and other acute health disorders.

The proposed rule will also result in substantial reductions of criteria pollutants such as CO, PM, and SO_2. Sulfur dioxide is a precursor pollutant that is often transformed into fine PM ($PM_{2.5}$) in the atmosphere; some of the directly-emitted PM is in the form of $PM_{2.5}$. Reducing emissions of PM and SO_2 will, as a result, reduce concentrations of $PM_{2.5}$ in the atmosphere. These reductions in $PM_{2.5}$ will provide large health benefits, such as reducing the risk of premature mortality for adults, chronic and acute bronchitis, childhood asthma attacks, and other respiratory and cardiovascular diseases. (For more details on the health effects of metals, organics, and $PM_{2.5}$, please refer to the RIA contained in the docket for this rulemaking.) This proposed rule will also have a small effect on electricity and natural gas prices and has the potential to affect the cost structure of the utility industry and could lead to shifts in how and where electricity is generated. Although energy prices are estimated to increase, we can only estimate national impacts. We are unable to determine impacts other than at the national level at this time.

Pursuant to EO 12898 and the "Interim Guidance on Considering Environmental Justice During the Development of an Action" (July 2010), during development of a rule EPA considers whether there are positive or negative impacts of the action that appear to affect low-income, minority, or tribal communities disproportionately. Regardless of whether a disproportionate effect exists, EPA also considers whether there is a chance for these communities to meaningfully participate in the rulemaking process.

Today's proposed rule is one of a group of regulatory actions that EPA will take over the next several years to respond to statutory and judicial mandates that will reduce exposure to HAP and $PM_{2.5}$, as well as to other pollutants, from EGUs and other sources. In addition, EPA will pursue energy efficiency improvements throughout the economy, along with other Federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements. Together, these rules and actions will have substantial and long-term effects on both the U.S. power industry and on communities currently breathing dirty air. Therefore, we anticipate significant interest in many, if not most, of these actions from EJ communities, among many others.

1. Key EJ Aspects of the Rule

This is an air toxics rule; therefore, it does not permit emissions trading among sources. Instead, this proposed rule will place a limit on the rates of Hg and other HAP emitted from each affected EGU. As a result, emissions of Hg and other HAP such as HCl will be substantially reduced in the vast majority of states. In some states, however, there may be small increases in Hg emissions due to shifts in electricity generation from EGUs with higher emission rates to EGUs with already low emission rates. Hydrogen chloride emissions are projected to increase at a small number of sources but that does not lead to any increased emissions at the state level.

The primary risk analysis to support the finding that this proposed rule is both appropriate and necessary includes an analysis of the effects of Hg from EGUs on people who rely on freshwater fish they catch as a regular and frequent part of their diet. These groups are characterized as subsistence level fishing populations or fishers. A significant portion of the data in this analysis came from published studies of EJ communities where people frequently consume locally-caught freshwater fish. These communities included: (1) White and black populations (including female and poor strata) surveyed in South Carolina; (2) Hispanic, Vietnamese and Laotian populations surveyed in California; and (3) Great Lakes tribal populations (Chippewa and Ojibwe) active on ceded territories around the Great Lakes. These data were used to help estimate risks to similar populations beyond the areas where the study data was collected. For example, while the Vietnamese and Laotian survey data were collected in California, given the ethnic (heritage) nature of these high fish consumption rates, we assumed that they could also be associated with members of these ethnic groups living elsewhere in the U.S. Therefore, the high-end consumption rates referenced in the California study for these ethnic groups were used to model risk at watersheds elsewhere in the U.S. As a result of this approach, the specific fish consumption patterns of several different EJ groups are fundamental to EPA's assessment of both the underlying risks that make this proposed rule appropriate and necessary, and of the analysis of the benefits of reducing exposure to Hg and the other hazardous air pollutants.

EPA's full analysis of risks from consumption of Hg-contaminated fish are contained in the preamble for this rule. The effects of this proposed rule on the health risks from Hg and other HAP are presented in the preamble and in the RIA for this rule. This information can be accessed through docket EPA–HQ–OAR–2009–0234 and from the main EPA webpage for the rule *http://www.epa.gov/ttn/atw/utility/utilitypg.html.*

2. Potential Environmental and Public Health Impacts to Vulnerable Populations

EPA has conducted several analyses that provide additional insight on the potential effects of this rule on EJ communities. These include: (1) The socio-economic distribution of people living close to affected EGUs who may be exposed to pollution from these sources; and (2) an analysis of the distribution of health effects expected from the reductions in $PM_{2.5}$ that will result from implementation of this proposed rule (so-called "co-benefits").

a. Socio-Economic Distribution. As part of the analysis for this proposed rule, EPA reviewed the aggregate demographic makeup of the communities near EGUs covered by this proposed rule. Although this analysis gives some indication of populations that may be exposed to levels of pollution that cause concern, it does NOT identify the demographic characteristics of the most highly affected individuals or communities. EGUs usually have very tall emission stacks; this tends to disperse the pollutants emitted from these stacks fairly far from the source. In addition, several of the pollutants emitted by these sources, such as Hg and SO_2, are known to travel long distances and harm both the environment and human health hundreds or even thousands of miles from where they were emitted.

This proximity-to-the-source review is included in the analysis for this proposed rule because some EGUs emit enough Ni or Cr to cause elevated lifetime cancer risks greater than 1 in a million in nearby communities. In addition, EPA's analysis indicates that there are localized areas with elevated levels of Hg deposition around most U.S. EGUs.

The review identified those census blocks within two circular distances (5 km and 50 km) of coal-fired EGUs and determined their demographic and socio-economic composition (*e.g.,* race, income, education, etc.). The radius of 5 km (or approximately 3 miles) was chosen because it has been used in other demographic analyses focused on areas around potential sources. The radius of 50 km (or approximately 31 miles) was used to approximate the distance from the source where elevated levels of Hg deposition might occur and may also be indicative of the area where risks from non-Hg HAP are most likely to occur.

The results of EPA's demographic analysis for coal fired EGUs are shown in the following table:

TABLE 30—COMPARATIVE SUMMARY OF THE DEMOGRAPHICS WITHIN 5 KM (3 MILES) AND 50 KM (31 MILES) OF THE AFFECTED SOURCES

	White (%)	African American (%)	Native American (%)	Other and multiracial (%)	Hispanic (%)	Minority (%)	Below poverty line (%)
5 km (3-mile) Buffer	70.8	15.8	0.7	12.7	15.5	35.5	15.6
50 km (31.1 miles) Buffer	74.5	15.2	0.5	9.7	9.9	29.7	11.6
National Average	75.1	12.3	0.9	11.7	13.7	31.6	13.1

The data indicate that coal-fired EGUs are located in areas where minority share of the population living within a 3-mile buffer is higher than the national average. For these same areas, the percent of the population below the poverty line is also higher than the national average. At 50 km from the source, however, the demographics are different. Although the percent African American remain above the national average, the percent of minority (including Native Americans) and the percent of the population living below the poverty line decrease below their respective national averages. These results are presented in more detail in the "Review of Proximity Analysis," February 2011, a copy of which is available in the docket.

b. $PM_{2.5}$ (Co-Benefits) Analysis. As mentioned above, many of the steps EGUs take to reduce their emissions of air toxics as required by this proposed rule will also reduce emissions of PM and SO_2. As a result, this proposed rule will reduce concentrations of $PM_{2.5}$ in the atmosphere. Exposure to $PM_{2.5}$ can cause or contribute to adverse health effects, such as asthma and heart disease, that significantly affect many minority, low-income, and tribal individuals and their communities. Fine PM ($PM_{2.5}$) is particularly (but not exclusively) harmful to children, the elderly, and people with existing heart and lung diseases, including asthma. Exposure can cause premature death and trigger heart attacks, asthma attacks in children and adults with asthma, chronic and acute bronchitis, and emergency room visits and hospitalizations, as well as milder illnesses that keep children home from school and adults home from work. Missing work due to illness or the illness of a child is a particular problem for people who work jobs that do not provide paid sick days. Many low-wage employees also risk losing their jobs if they are absent too often, even if it is due to their own illness or the illness of a child or other relative. Finally, many individuals in these communities also lack access to high quality health care to treat these types of illnesses. Due to all these factors, many minority and low-income communities are particularly susceptible to the health effects of $PM_{2.5}$ and receive many benefits from reducing it.

We estimate that in 2016 the PM-related annual benefits of the proposed rule for adults include approximately 6600 to 17,000 fewer premature mortalities, 4,300 fewer cases of chronic bronchitis, 10,000 fewer non-fatal heart attacks, 12,000 fewer hospitalizations (for respiratory and cardiovascular disease combined), 4.9 million fewer days of restricted activity due to respiratory illness and approximately 830,000 fewer lost work days. We also estimate substantial health improvements for children in the form of 110,000 fewer asthma attacks, 6,700 fewer hospital admissions due to asthma, 10,000 fewer cases of acute bronchitis, and approximately 210,000 fewer cases of upper and lower respiratory illness.

We also examined the $PM_{2.5}$ mortality risks according to race, income, and educational attainment. We then estimated the change in $PM_{2.5}$ mortality risk as a result of this proposed rule among people living in the counties with the highest (top 5 percent) $PM_{2.5}$ mortality risk in 2005. We then compared the change in risk among the people living in these "high-risk" counties with people living in all other counties.

In 2005, people living in the highest-risk counties and in the poorest counties have substantially higher risks of $PM_{2.5}$-related death than people living in the other 95 percent of counties. This was true regardless of race; the difference between the groups of counties for each race is large while the differences among races in both groups of counties is very small. In contrast, the analysis found that people with less than high school education have significantly greater risks from $PM_{2.5}$ mortality than people with a greater than high school education. This was true both for the highest-risk counties and for the other counties. In summary, the analysis indicates that in 2005, educational status, living in one of the poorest counties, and living in a high-risk county are associated with higher $PM_{2.5}$ mortality risk while race is not.

Our analysis finds that this proposed rule will significantly reduce the $PM_{2.5}$ mortality among all populations of different races living throughout the U.S. compared to both 2005 and 2016 pre-rule (i.e., base case) levels. The analysis indicates that people living in counties with the highest rates (top 5 percent) of $PM_{2.5}$ mortality risk in 2005 receive the largest reduction in mortality risk after this rule takes effect. We also find that people living in the poorest 5 percent of the counties receive a larger reduction in $PM_{2.5}$ mortality risk than all other counties. More information can be found in Appendix C of the RIA.

EPA estimates that the benefits of the proposed rule are distributed among these populations fairly evenly. Therefore, there is no indication that people of particular race, income, or level of education receive a greater benefit (or smaller benefit) than others. However, the analysis does indicate that this proposed rule in conjunction with the implementation of existing or proposed rules (*e.g.,* the Transport Rule) will reduce the disparity in risk between those in the highest-risk counties and the other 95 percent of counties for all races and educational levels. In addition, in many cases implementation of this proposed rule and other rules will, together, reduce risks in the highest-risk counties to the approximate level of risk for the rest on the counties before implementation.

These results are presented in more detail in the "Benefits Appendix" to this rule, a copy of which is available in the docket.

3. Meaningful Public Participation

EPA defines "Environmental Justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and polices. To promote meaningful involvement, EPA has developed a communication and outreach strategy to ensure that interested communities have access to this proposed rule, are aware of its content, and have an opportunity to comment during the comment period. During the comment period, EPA will publicize the rulemaking via newsletters, EJ listserves, webinars and the internet, including the Office of Policy's (OP) Rulemaking Gateway Web site (*http://yosemite.epa.gov/opei/RuleGate.nsf/*). EPA will also provide general rulemaking fact sheets (*e.g.,* why is this important for my community) for EJ community groups and conduct conference calls with interested communities.

Once this rule is finalized and implemented, affected EGUs will need to update their operating (Title V) permits to reflect their new emissions limits and any other applicable requirements (*i.e.,* monitoring and recordkeeping) from this rule. The Title V permitting process provides that most permit actions must include an opportunity for public review and comments. In addition, after the public review process, EPA has an opportunity to review the proposed permit and object to its issuance if it does not meet CAA requirements. This process gives members of affected communities the opportunity to comment on the permit conditions for specific sources affected by this rulemaking.

4. Summary

This proposed rule strictly limits the emissions rate of Hg and other HAP from every affected EGU in the U.S. EPA's analysis indicates substantial health benefits, including for vulnerable populations, from reductions in $PM_{2.5}$. EPA's analysis also indicates reductions in risks for individuals, including for members of many minority populations, who eat fish frequently from U.S. lakes and rivers and who live near affected sources. Based on all the available information, EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority, low-income, or tribal populations. EPA is providing multiple opportunities for EJ communities to both learn about and comment on this rule and welcomes their participation.

List of Subjects in 40 CFR Parts 60 and 63

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

Dated: March 16, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of the Federal Regulations is proposed to be amended as follows:

PART 60—[AMENDED]

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

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

Subpart A-—[Amended]

2. Section 60.17 is amended:

a. By redesignating paragraphs (a)(91) and (a)(92) as paragraphs (a)(94) and (a)(95);

b. By redesignating paragraphs (a)(89) and (a)(90) as paragraphs (a)(91) and (a)(92);

c. By redesignating paragraphs (a)(54) through (a)(88) as paragraphs (a)(55) through (a)(89);

d. By adding paragraph (a)(54);

e. By adding paragraph (a)(90); and

f. By adding paragraph (a)(93) to read as follows:

§ 60.17 Incorporations by Reference.

* * * * *

(54) ASTM D3699—08, Standard Specification for Kerosine, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(90) ASTM D6751–11, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(94) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

Subpart D—[Amended]

3. The heading to Subpart D is revised to read as follows:

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators

4. Section 60.40 is amended by revising paragraph (e) to read as follows:

§ 60.40 Applicability and designation of affected facility.

* * * * *

(e) Any facility covered under either subpart Da or KKKK is not covered under this subpart.

5. Section 60.41 is amended by adding the definitions of "natural gas" to read as follows:

§ 60.41 Definitions.

* * * * *

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

* * * * *

6. Section 60.42 is amended as follows:

a. By revising paragraph (a) introductory text.

b. By adding paragraph (d).

c. By adding paragraph (e).

§ 60.42 Standard for Particulate Matter (PM).

(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:

* * * * *

(d) An owner and operator of an affected facility that combusts only natural gas and that is subject to a federally enforceable permit limiting fuel use to natural gas is exempt from the PM and opacity standards specified in paragraph a of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM is exempt from the PM standards specified in paragraph a of this section.

7. Section 60.45 is amended as follows:

a. By revising paragraph (a).

b. By revising paragraphs (b) introductory text and (b)(1) through (b)(5).

c. By revising paragraph (b)(6) introductory text.

§ 60.45 Emissions and Fuel Monitoring.

(a) Each owner or operator of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring SO_2 emissions, NO_X emissions, and either oxygen (O_2) or carbon dioxide (CO_2) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS and COMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil-fuel-fired steam generator that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO_2 emissions are not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO_2 emissions is not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis.

(3) Notwithstanding § 60.13(b), installation of a CEMS for NO_X may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of NO_X are less than 70 percent of the applicable standards in § 60.44, a CEMS for measuring NO_X emissions is not required. If the initial performance test results show that NO_X emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO_X within one year after the date of the initial performance tests under § 60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator is not required to and elects not to install any CEMS for SO_2 and NO_X, a CEMS for measuring either O_2 or CO_2 is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for an affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

* * * * *

Subpart Da—[Amended]

8. The heading to Subpart Da is revised to read as follows:

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units

9. Section 60.40Da is amended by revising paragraph (e) and by adding paragraph (f) to read as follows:

§ 60.40Da Applicability and designation of affected facility.

* * * * *

(e) Applicability of the requirement of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as specified in paragraphs (e)(1) through (e)(3) of this section.

(1) Affected facilities (i.e. heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel are subject to this subpart except in cases when the affected facility (i.e. heat recovery steam generator) meets the applicability requirements and is subject to subpart KKKK of this part.

(2) For heat recovery steam generators used with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (i.e. duct burners) are subject to the standards under this subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKKK, as applicable, of this part).

(3) Any affected facility that meets the applicability requirements and is subject to subpart Eb or subpart CCCC of this part is not subject to the emission standards under subpart Da.

(f) *General Duty to minimize emissions.* At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

10. Section 60.41Da is amended by revising the definitions of "gaseous fuel," "integrated gasification combined cycle electric utility steam generating unit," "petroleum" and "steam generating unit," adding the definitions of "affirmative defense" and "petroleum coke," and deleting the definitions of "dry flue gas desulfurization technology," "emission rate period," and "responsible official" to read as follows:

§ 61.41Da Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

Gaseous fuel means any fuel that is present as a gas at standard conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

* * * * *

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction or repair. No solid fuel is directly burned in the unit during operation.

* * * * *

Petroleum for facilities constructed, reconstructed, or modified before May 4, 2011, means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, and residual oil. For units constructed, reconstructed, or modified after May 3, 2011, Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, residual oil, and petroleum coke.

* * * * *

Petroleum Coke, also known as *petcoke,* means a carbonization product of high-boiling hydrocarbon fractions obtained in petroleum processing (heavy residues). Petroleum coke is typically derived from oil refinery coker units or other cracking processes.

* * * * *

Steam generating unit for facilities constructed, reconstructed, or modified before May 4, 2011, 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). For units constructed, reconstructed, or modified after May 3, 2011, 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) plus any integrated combustion turbines and fuel cells.

* * * * *

11. Revise § 60.42Da to read as follows:

§ 60.42Da Standard for particulate matter (PM).

(a) Except as provided in paragraph (a)(4) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before March 1, 2005, any gases that contain filterable PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(4) An owner or operator of an affected facility that combusts only gaseous or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO_2 or PM is exempt from the PM standard specified in paragraphs (a)(1), (a)(2), and (a)(3) of this section:

(b) Except as provided in paragraphs (b)(1) and (b)(2) of this section, on and after the date the initial PM performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(1) Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart are exempt from the opacity standard specified in this paragraph (b) of this section.

(2) An owner or operator of an affected facility that combusts only natural gas is exempt from the opacity standard specified in paragraph (b) of this section.

(c) Except as provided in paragraphs (d) and (e) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain filterable PM in excess of either:

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

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, may elect to meet the requirements of this paragraph. For an affected facility that commenced construction, reconstruction, or modification, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator shall cause to be discharged into the atmosphere from that affected facility any gases that contain filterable PM in excess of:

(1) 13 ng/J (0.030 lb/MMBtu) heat input, and

(2) For an affected facility that commenced construction or reconstruction, 0.1 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.9 percent reduction) when combusting solid, liquid, or gaseous fuel, or

(3) For an affected facility that commenced modification, 0.2 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.8 percent reduction) when combusting solid, liquid, or gaseous fuel.

(e) An owner or operator of an affected facility than combusts only gaseous or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and that does not use a post-combustion technology to reduce emissions of SO_2 or PM is exempt from the PM standard specified in paragraphs (c) of this section.

(f) Except as provided in paragraph (g) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, modification, or reconstruction after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain total PM in excess of either:

(1) For an affected facility that commenced construction or reconstruction 7.0 ng/J (0.055 lb/MWh) gross energy output; or

(2) For an affected facility that commenced modification, 15 ng/J (0.034 lb/MMBtu) heat input.

(g) An owner or operator of an affected facility that combusts only natural gas is exempt from the total PM standard specified in paragraph (f) of this section.

(h) The PM emission standards under this section do not apply to an owner or operator of any affected facility that is operated under a PM commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

12. Section 60.43Da is amended as follows:

a. By revising paragraphs (a)(1) through (a)(3).

b. By revising paragraph (f).

c. By revising paragraph (i).

d. By revising paragraph (j).

e. By revising paragraph (k).

f. By adding paragraph (a)(4).
g. By adding paragraph (l).
h. By adding paragraph (m).
i. By adding paragraph (n).

§ 60.43Da Standard for sulfur dioxide (SO_2).

(a) * * *

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction);

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input;

(3) 180 ng/J (1.4 lb/MWh) gross energy output; or

(4) 65 ng/J (0.15 lb/MMBtu) heat input.

* * * * *

(f) The SO_2 standards under this section do not apply to an owner or operator of an affected facility that is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

* * * * *

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility which commenced construction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction).

(2) For an affected facility which commenced reconstruction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction).

(3) For an affected facility which commenced modification, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction).

(j) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility which commenced construction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 6 percent of the potential combustion concentration (94 percent reduction).

(2) For an affected facility which commenced reconstruction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 6 percent of the potential combustion concentration (94 percent reduction).

(3) For an affected facility which commenced modification, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction).

(k) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area that commenced construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

(l) Except as provided in paragraphs (m) and (n) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emission limitation specified in paragraphs (l)(1) or (2) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain SO_2 in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 3 percent of the potential combustion concentration (97 percent reduction).

(2) For an affected facility which commenced modification, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 10 percent of the potential combustion concentration (90 percent reduction).

(m) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after May 3, 2011, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, shall caused to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emission limitation specified in paragraphs (m)(1) or (2) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 6 percent of the potential combustion concentration (94 percent reduction).

(2) For an affected facility which commenced modification, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 10 percent of the potential combustion concentration (90 percent reduction).

(n) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area that commenced construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emission limitation specified in paragraphs (n)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

13. Section 60.44Da is amended:

a. By revising paragraph (a) introductory text.

b. By revising paragraph (b).

c. By revising paragraph (d).

d. By revising paragraph (e).

e. By revising paragraph (f).

f. By adding paragraph (g).

g. By adding paragraph (h).

§ 60.44Da Standard for nitrogen oxides (NO).

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b), (d), (e), and (f) of this section, any gases that contain NO_X (expressed as NO_2) in excess of the following emission limits:

* * * * *

(b) The NO_X emission limitations under this section do not apply to an owner or operator of an affected facility which is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

(d)(1) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction after July 9, 1997, but before March 1, 2005 shall cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, except as provided under § 60.48Da(k).

(2) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of affected facility for which reconstruction commenced after July 9, 1997, but before March 1, 2005 shall cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 65 ng/J (0.15 lb/MMBtu) heat input.

(e) Except as provided in paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility which commenced construction, any gases that contain NO_X (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output, except as provided under § 60.48Da(k).

(2) For an affected facility which commenced reconstruction, any gases that contain NO_X (expressed as NO_2) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input.

(3) For an affected facility which commenced modification, any gases that contain NO_X (expressed as NO_2) in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input.

(f) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005 but before May 4, 2011, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

(3) In cases when during a 30 boiler operating day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

(g) Compliance with the emission limitations under this section are determined on a 30-boiler operating day rolling average basis, except as provided under § 60.48Da(j)(1).

(h) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of 88 ng/J (0.70 lb/MWh) gross energy output.

§ 60.45Da [Removed and Reserved]

14. Remove and reserve § 60.45Da.

15. Section 60.47Da is amended as follows:

a. By adding paragraph (f).

b. By adding paragraph (g).

c. By adding paragraph (h).

d. By adding paragraph (i).

Section 60.47Da Commercial demonstration permit.

* * * * *

(f) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the total PM emission reduction requirements under § 60.42Da but must, as a minimum, reduce PM emissions to less than 15 ng/J (0.034 lb/MMBtu) heat input.

(g) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 standards or emission reduction requirements under § 60.43Da but must, as a minimum, reduce SO_2 emissions to 5 percent of the potential combustion concentration (95 percent reduction) or to less than 180 ng/J (1.4 lb/MWh) gross output on a 30 boiler operating day rolling average basis.

(h) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system or advanced combustion controls who is issued a commercial demonstration permit by the Administrator is not subject to the NO_X standards or emission reduction requirements under § 60.44Da but must, as a minimum, reduce NO_X emissions to less than 130 ng/J (1.0 lb/MWh) gross output on a 30 boiler operating day rolling average basis.

(i) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	SO_2	1,000
Multi-pollutant Emission Control	NO_X	1,000
Multi-pollutant Emission Control	PM	1,000
Pressurized Fluidized Bed Combustion	SO_2	1,000
Pressurized Fluidized Bed Combustion	NO_X	1,000
Pressurized Fluidized Bed Combustion	PM	1,000
Advanced Combustion Controls	NO_X	1,000

16. Section 60.48Da is amended as follows:

a. By revising paragraph (c).
b. By revising paragraph (g).
c. By revising paragraph (k)(1)(i).
d. By revising paragraph (k)(1)(ii).
e. By revising paragraph (k)(2)(i).
f. By revising paragraph (k)(2)(iv).
g. By removing and reserving paragraph (l).
h. By revising paragraph (n).
i. By revising paragraphs (p)(5), (p)(7), and (p)(8).
j. By adding paragraph (r).

Section 60.48a Compliance provisions.

* * * * *

(c) For affected facilities that commenced construction, modification, or reconstruction before May 4, 2011, the PM emission standards under § 60.42Da, and the NO_X emission standards under § 60.44Da apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under § 60.43Da apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under paragraph (d) of this section are implemented. For affected facilities that commence construction, modification, or reconstruction after May 3, 2011, the PM emission standards under § 60.42Da, the NO_X emission standards under § 60.44Da, and the sulfur dioxide emission standards under § 60.43Da apply at all times.

* * * * *

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

(1) For affected facilities that commenced construction, modification, or reconstruction before May 4, 2011, compliance with applicable 30 boiler operating day rolling average SO_2 and NO_X emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_X only), or emergency conditions (SO_2 only). For affected facilities that commence construction, modification, or reconstruction after May 3, 2011, compliance with applicable 30 boiler operating day rolling average SO_2 and NO_X emission limitations is determined by dividing the sum of all the SO_2 and NO_X emissions for the 30 successive boiler operating days divided by the sum of all the gross useful output for the 30 successive boiler operating days.

(2) For affected facilities that commenced construction, modification, or reconstruction before May 4, 2011, compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days. For affected facilities that commence construction, modification, or reconstruction after May 3, 2011, compliance with applicable SO_2 percentage reduction requirements is determined based on the "as fired" total potential emissions and the total outlet SO_2 emissions for the 30 successive boiler operating days.

(3) For affected facilities that commenced construction, modification, or reconstruction before May 4, 2011 compliance with applicable daily average PM emission limitations is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. For affected facilities that commence construction, modification, or reconstruction after May 3, 2011, compliance with applicable daily average PM emission limitations is determined by calculating the sum of all PM emissions for PM each boiler operating day divided by the sum of all the gross useful output for PM each boiler operating day, except for data obtained during malfunction. Averages are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control data daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance.

* * * * *

(k) * * *

(1) * * *

(i) The emission rate (E) of NO_X shall be computed using Equation 2 in this section:

$$E = \frac{(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})}{(O_{sg} \times h)} \qquad \text{(Eq. 2)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross output;
C_{sg} = Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);
C_{te} = Average hourly concentration of NO_X in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);
Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr);
Q_{te} = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr);
O_{sg} = Average hourly gross energy output from steam generating unit, J/h (MW); and
h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

* * * * *

(2) * * *

(i) The emission rate (E) of NO_X shall be computed using Equation 3 in this section:

$$E = \frac{(C_{sg} \times Q_{sd})}{O_{cc}} \qquad \text{(Eq. 3)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross output;
C_{sg} = Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);
Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr); and
O_{cc} = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in § 60.49Da(l), determine the mass rate (lb/hr) of NO_X emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NO_X shall be computed using Equation 4 in this section:

$$E = \frac{(ER_{sg} \times H_{cc})}{O_{cc}} \qquad \text{(Eq. 4)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross output;
ER_{sg} = Average hourly emission rate of NO_X exiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);
H_{cc} = Average hourly heat input rate of entire combined cycle unit, J/hr (MMBtu/hr); and
O_{cc} = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(n) Compliance provisions for sources subject to § 60.42Da(c)(1). The owner or operator of an affected facility subject to § 60.42Da(c)(1) shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of § 60.49Da(t)), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)).

* * * * *

(p) * * *

(5) At a minimum, non-out-of-control valid CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30 boiler operating day rolling average basis. Beginning on January 1, 2012, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30 boiler operating day rolling average basis.

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

(ii) [Reserved]

* * * * *

(7) All non-out-of-control CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator to provide, as necessary, non-out-of-control emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30 boiler operating day rolling average.

* * * * *

(r) *Affirmative Defense for Exceedance of Emission Limit During Malfunction.* In response to an action to enforce the standards set forth in paragraph §§ 60.42Da, 60.43Da, and 60.44Da, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) The owner or operator of the facility experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standards in §§ 60.42Da, 60.43Da, and 60.44Da to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

17. Section 60.49Da is amended as follows:

a. By revising paragraphs (a)(1), (a)(2), and (a)(3) introductory text.

b. By revising paragraphs (b) introductory text and (b)(2).

c. By revising paragraph (e).

d. By revising paragraph (k) introductory text.

e. By revising paragraph (l).

f. By removing and reserving paragraph (p).

g. By removing and reserving paragraph (q).

h. By removing and reserving paragraph (r).

i. By revising paragraph (t).

j. By revising paragraphs (u)(1)(iii) and (u)(4).

§ 60.49Da Emission monitoring.

(a) * * *

(1) Except as provided for in paragraph (a)(2) of this section, the owner or operator of an affected facility subject to an opacity standard, shall install, calibrate, maintain, and operate a COMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO_2 control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), (iii), or (iv) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

(i) The affected facility uses a fabric filter (baghouse) to meet the standards in § 60.42Da and a bag leak detection system is installed and operated according to the requirements in paragraphs § 60.48Da(o)(4)(i) through (v);

(ii) The affected facility burns only gaseous or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO_2 or PM;

(iii) The affected facility meets all of the conditions specified in paragraphs (a)(2)(iii)(A) through (C) of this section; or

(A) No post-combustion technology (except a wet scrubber) is used for reducing PM, SO_2, or carbon monoxide (CO) emissions;

(B) Only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur are burned; and

(C) Emissions of CO discharged to the atmosphere are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis as demonstrated by the use of a CEMS measuring CO emissions according to the procedures specified in paragraph (u) of this section.

(iv) The affected facility uses an ESP and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part.

(3) The owner or operators of an affected facility that meets the conditions in paragraph (a)(2) of this section may, as an alternative to using a COMS, elect to monitor visible emissions using the applicable procedures specified in paragraphs (a)(3)(i) through (iv) of this section. The opacity performance test requirement in paragraph (a)(3)(i) must be conducted by April 29, 2011, within 45 days after stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later.

* * * * *

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, except where natural gas and/or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less are the only fuels combusted, as follows:

* * * * *

(2) For a facility that qualifies under the numerical limit provisions of § 60.43Da SO_2 emissions are only monitored as discharged to the atmosphere.

* * * * *

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction, and emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

* * * * *

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with an output-based standard.

* * * * *

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the CD assessment, RATA and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under § 60.42Da shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected facility demonstrating compliance with the input-based emission limitation in § 60.42Da may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) * * *

(1) * * *

(iii) At a minimum, non-out-of-control 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30 boiler operating day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

* * * * *

(4) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (i.e., reference method) data and performance test (i.e., compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFire database.

18. Section 60.50Da is amended as follows:

a. By revising paragraphs (b)(2) and (b)(4).

b. By removing paragraph (g).

c. By removing paragraph (h).

d. By removing paragraph (i).

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(b) * * *

(2) For the filterable particular matter concentration, Method 5 of appendix A of this part shall be used at affected facilities without wet FGD systems and Method 5B of appendix A of this part shall be used after wet FGD systems.

* * * * *

(4) Total particular matter concentration consists of the sum of the filterable and condensable fractions. The condensable fraction shall be measured using Method 202 of appendix M of part 51, and the filterable fraction shall be measured using Method 5 of appendix A of this part.

* * * * *

19. Section 60.51Da is amended as follows:

a. By revising paragraph (a).

b. By removing and reserving paragraph (g).

c. By revising paragraph (k).

§ 60.51 Da Reporting requirements.

(a) For SO_2, NO_X, and PM 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.

* * * * *

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period.

§ 60.52Da(a) [Removed and reserved]

20. Section 60.52Da is amended by removing and reserving paragraph (a).

Subpart Db—[Amended]

21. Section 60.40b is amended as follows:

a. By revising paragraph (c).

b. By revising paragraph (h).

c. By revising paragraph (i).

d. By adding paragraph (1).

§ 60.40b Applicability and delegation of affected facility.

* * * * *

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja (Standards of performance for petroleum refineries) are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja.

* * * * *

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities (i.e. heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (i.e. heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the affected facility (i.e. heat recovery steam generator) is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

* * * * *

(l) Affected facilities that also meet the applicability requirements under subpart BB (Standards of Performance for Kraft Pulp Mills) are subject to the SO_2 and NO_X standards under this subpart and the PM standards under subpart BB.

* * * * *

22. Section 60.41b is amended by revising the definition of "distillate oil" to read as follows:

§ 60.41b Definitions.

* * * * *

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 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosene, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

* * * * *

23. Section 60.44b is amended by revising paragraphs (c) and (d) to read as follows:

§ 60.44b Standard for nitrogen oxides (NO).

* * * * *

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

* * * * *

24. Section 60.46b is amended by revising paragraph (j)(14) to read as follows:

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

* * * * *

(j) * * *

(14) As of January 1, 2012, and within 60 days after the date of completing each performance test, as defined in § 63.2, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (i.e., reference method) data and performance test (i.e., compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

25. Section 60.48b is amended as follows:

a. By revising paragraphs (a) introductory text and (a)(1)(i).

b. By revising paragraph (j) introductory text.

c. By revising paragraph (j)(5).

d. By revising paragraph (j)(6).

e. By adding paragraph (j)(7).

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

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

* * * * *

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

* * * * *

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

* * * * *

Subpart Dc—[Amended]

26. Section 60.40c is amended as follows:

a. By revising paragraph (e).
b. By revising paragraph (f).
c. By revising paragraph (g).

§ 60.40c Applicability and delegation of authority.

* * * * *

(e) Affected facilities (i.e. heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements of and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

27. Section 60.41c is amended by removing the definition of "Cogeneration" and revising the definition of "Distillate oil" to read as follows:

§ 60.41c Definitions.

* * * * *

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and

Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosene, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

* * * * *

28. Section 60.42c is amended as follows:

a. By revising paragraph (d).

b. By revising paragraph (h) introductory text.

c. By revising paragraph (h)(3).

d. By adding paragraph (h)(4).

§ 60.42c Standard for sulfur dioxide (SO_2).

* * * * *

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

* * * * *

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

* * * * *

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

* * * * *

29. Section 60.45c is amended by revising paragraph (c)(14) to read as follows:

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

* * * * *

(c)(14) As of January 1, 2012, and within 60 days after the date of completing each performance test, as defined in § 63.2, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (i.e., reference method) data and performance test (i.e., compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

* * * * *

30. Section 60.47c is amended as follows:

a. By revising paragraphs (a) introductory text and (a)(1)(i).

b. By revising paragraph (f).

c. By revising paragraph (g).

d. By adding paragraph (h).

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), (f), (g), and (h) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), (f), or (g) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

* * * * *

(f) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part is not required to operate a COMS.

(g) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part.

(h) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that burns only gaseous fuels and/or fuel oils that contain less than or equal to 0.5 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

Subpart HHHH—[Removed and Reserved]

31. Subpart HHHH is removed and reserved.

PART 63—[AMENDED]

32. The authority citation for part 63 continues to read as follows:

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

33. Part 63 is amended by adding subpart UUUUU to read as follows:

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Sec.

What This Subpart Covers

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

What This Subpart Covers

§ 63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs). This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§ 63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU.

§ 63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of one or more new, reconstructed, and existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs as defined in § 63.10042.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in § 63.10042.

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011, and you meet the applicability criteria at the time you commence construction.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after May 3, 2011, and you meet the applicability criteria at the time you commence reconstruction.

(d) An EGU is existing if it is not new or reconstructed. An existing electric utility steam generating unit that has switched completely to burning a different coal rank or fuel type is considered to be an existing affected source under this subpart.

§ 63.9983 Are any EGUs not subject to this subpart?

The types of EGUs listed in paragraphs (a) through (c) of this section are not subject to this subpart.

(a) Any unit designated as a stationary combustion turbine, other than an integrated gasification combined cycle (IGCC), covered by 40 CFR part 63, subpart YYYY.

(b) Any EGU that is not a coal- or oil-fired EGU and combusts natural gas more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years.

(c) Any EGU that has the capability of combusting more than 73 MWe (250 million Btu/hr, MMBtu/hr) heat input (equivalent to 25 MWe output) of coal or oil but did not fire coal or oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).

§ 63.9984 When do I have to comply with this subpart?

(a) If you have a new or reconstructed EGU, you must comply with this subpart by [DATE THE FINAL RULE IS PUBLISHED IN THE **FEDERAL REGISTER**] or upon startup of your EGU, whichever is later.

(b) If you have an existing EGU, you must comply with this subpart no later than [3 YEARS AFTER DATE THE FINAL RULE IS PUBLISHED IN THE **FEDERAL REGISTER**].

(c) You must meet the notification requirements in § 63.10030 according to the schedule in § 63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

Emission Limitations and Work Practice Standards

§ 63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (a)(2) of this section and as defined in § 63.10042.

(1) EGUs designed for coal ≥ 8,300 Btu/lb, and

(2) EGUs designed for coal < 8,300 Btu/lb. (b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(2) of this section and as defined in § 63.10042.

(1) EGUs designed to burn liquid oil, and

(2) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under paragraph (a)(1)(i) and (ii) or under § 63.10009.

(i) You may not use the alternate SO_2 limit if your coal-fired EGU does not have a system using wet or dry flue gas desulfurization technology installed on the unit.

(ii) You may not use the alternate SO_2 limit if your oil-fired EGU does not have a system using wet or dry flue gas desulfurization technology installed on the unit.

(iii) You must operate the wet or dry flue gas desulfurization technology installed on the unit at all times in order to qualify to use the alternate SO_2 limit.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

General Compliance Requirements

§ 63.10000 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c)(1) For coal-fired units and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants. For non-mercury HAP metals, you demonstrate continuous compliance through use of a particulate matter (PM) CEMS; initial compliance is determined by establishing an operational limit for filterable PM obtained during total PM emissions testing. As an alternative to using a PM CEMS, you may demonstrate initial and continuous compliance by conducting total HAP metals testing or individual non-mercury (Hg) metals testing. For acid gases, you demonstrate initial and continuous compliance through use of a continuous hydrogen chloride (HCl) CEMS. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting performance testing. As another alternative to HCl CEMS, you may demonstrate initial and continuous compliance through use of a certified sulfur dioxide (SO_2) CEMS, provided the unit has a system using wet or dry flue gas desulfurization technology. For mercury (Hg), if your unit does not qualify as a low emitting EGU (LEE), you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system.

(2) For liquid oil-fired units, you must demonstrate initial and continuous compliance for HCl, hydrogen fluoride (HF), and individual or total HAP metals by conducting performance testing. As an alternative to conducting performance testing, you may demonstrate compliance with the applicable emissions limit for HCl, HF, and individual or total HAP metals using fuel analysis provided the emission rate calculated according to § 63.10011(c) is less than the applicable emission limit.

(d) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), or through the use of a sorbent trap monitoring system for Hg, you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS or sorbent trap monitoring system. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B to part 60 or Part 75 of this chapter, and that meet the requirements of § 63.10010. The monitoring plan must address the provisions in paragraphs (d)(1) through (7) of this section.

(1) Installation of the CMS or sorbent trap monitoring system 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) Schedule for conducting initial and periodic performance evaluations.

(4) Performance evaluation procedures and acceptance criteria (e.g., calibrations), including ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d) or Appendix A to this subpart, as applicable.

(5) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii) or Appendix A to this subpart, as applicable.

(6) Conditions that define a continuous monitoring system that is out of control consistent with § 63.8(c)(7)(i) and for responding to out of control periods consistent with §§ 63.8(c)(7)(ii) and (c)(8) or Appendix A to this subpart, as applicable.

(7) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1), and (e)(2)(i) and Appendix A to this subpart, as applicable.

(e) You must operate and maintain the CMS or sorbent trap monitoring system according to the site-specific monitoring plan.

§ 63.10001 Affirmative Defense for Exceedence of Emission Limit During Malfunction.

In response to an action to enforce the standards set forth in paragraph § 63.9991 you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed, however, if the respondent fails to meet its burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, the owners or operators of facilities must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) The owner or operator of the facility experiencing an exceedence of its emission limit(s) during a malfunction shall notify the EPA Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two (2) business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the EPA Administrator within 45 days of the initial occurrence of the exceedence of the standard in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedances.

Testing, Fuel Analyses, and Initial Compliance Requirements

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) *General requirements.* Affected EGUs must demonstrate initial compliance with each of the applicable emissions limits in Tables 1 or 2 of this subpart through performance testing, along with one or more of the following activities: conducting a fuel analysis for each type of fuel combusted, establishing operating limits where applicable according to § 63.10011 and Table 7 to this subpart; conducting CMS performance evaluations where applicable; and conducting sorbent trap monitoring system performance evaluations, where applicable, in conjunction with performance testing. If you use a CMS that measures pollutant concentrations directly (i.e., a CEMS or a sorbent trap monitoring system), the performance test consists of the first 30 operating days of data collected with the certified monitoring system, after the applicable compliance date. If you use a continuous monitoring system that measures a surrogate for a pollutant (e.g., an SO_2 monitor), you must perform initial emission testing during the same compliance test period and under the same process (e.g., fuel) and control device operating conditions of the pollutant and surrogate, in addition to conducting the initial 30-day performance test. If you wish to demonstrate that a unit qualifies as a low emitting EGU (LEE), you must conduct performance testing in accordance with paragraphs (k) and (l) of this section.

(b) *Performance Testing Requirements.* Affected EGUs must demonstrate initial compliance with each of the applicable emissions limits in Tables 1 or 2 of this subpart by conducting performance tests according to § 63.10007 and Table 5 to this subpart.

(1) For affected EGUs that do not rely on CMS, sorbent trap monitoring systems, or 28 to 30 day Method 30B testing to demonstrate initial compliance, performance test data and results from a prior performance test may be used to demonstrate initial compliance, provided the performance tests meet the following conditions:

(i) The performance test was conducted within the last twelve months;

(ii) The performance test was conducted in accordance with all requirements contained in § 63.10007 and Table 5 of this subpart; and

(iii) You certify, and have and keep documentation demonstrating, that the EGU configuration, control devices, and materials/fuel have remained constant since the prior performance test was conducted.

(2) [Reserved]

(c) *Fuel Analysis Requirements.* Affected liquid oil-fired EGUs may choose to demonstrate initial compliance with each of the applicable emissions limits in Tables 1 or 2 of this subpart by conducting a fuel analysis for each type of fuel combusted, except those affected EGUs that meet the exemptions identified in paragraphs (c)(4) and (5) of this section and those affected EGUs that opt to comply with the individual or total HAP metals limits in Tables 1 or 2 of this subpart which must comply by conducting a fuel analysis as described in paragraph (c)(1) of this section.

(1) For affected liquid oil-fired EGUs demonstrating compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for HCl or individual or total HAP metals through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your EGU according to § 63.10008 and Table 6 to this subpart and establish operating limits according to § 63.10011 and Table 8 to this subpart.

(2) For affected liquid oil-fired EGUs that elect to demonstrate compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for HF, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your EGU according to § 63.10008 and Table 6 to this subpart and establish operating limits according to § 63.10011 and Table 8 to this subpart.

(3) Fuel analysis data and results from a prior fuel analysis may be used to demonstrate initial compliance, provided the fuel analysis meets the following conditions:

(i) The fuel analysis was conducted within the last twelve months;

(ii) The fuel analysis was conducted in accordance with all requirements contained in § 63.10008 and Table 6 of this subpart; and

(iii) You certify, and have and keep documentation demonstrating, that the EGU configuration, control devices, and materials/fuel have remained constant since the prior fuel analysis was conducted.

(4) For affected EGUs that combust a single type of fuel, you are exempted from the initial compliance requirements of conducting a fuel analysis for each type of fuel burned in your EGU according to § 63.10008 and Table 6 to this subpart.

(5) For purposes of this subpart, EGUs that use a supplemental fuel only for startup, unit shutdown, or transient flame stability purposes qualify as affected EGUs that combust a single type of fuel, the supplemental fuel is not subject to the fuel analysis requirements under § 63.10008 and Table 6 to this subpart, and you are exempted from the initial compliance requirements of conducting a fuel analysis for each type of fuel burned in your EGU according to § 63.10008 and Table 6 to this subpart.

(d) *CMS Requirements.* (1) For affected liquid oil-fired EGUs that elect to demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for HCl through use of HCl CEMS, initial compliance is determined using the average hourly HCl concentrations obtained during the first 30 day operating period after the monitoring system is certified.

(2) For affected liquid oil-fired EGUs that elect to demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for HF through use of HF CEMS, initial compliance is determined using the average hourly HF concentrations obtained during the first 30 day operating period after the monitoring system is certified.

(3) For affected solid oil-derived fuel- or coal-fired EGUs that demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for HCl through use of HCl CEMS, initial compliance is determined using the average hourly HCl concentrations obtained during the first 30 day operating period after the monitoring system is certified.

(4) For affected solid oil-derived fuel- or coal-fired EGUs with installed systems that use wet or dry flue gas desulfurization technology to demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for SO_2 through use of SO_2 CEMS, initial compliance is determined using the average hourly SO_2 concentrations obtained during the first 30 day operating period after the monitoring system is certified.

(5) For affected solid oil-derived fuel- or coal-fired EGUs that demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for PM through use of PM CEMS, initial compliance is determined using the average hourly PM concentrations obtained during the first 30 day operating period after the monitoring system is certified.

(6) For affected EGUs that demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for Hg through use of Hg CEMS, initial compliance is determined using the average hourly Hg concentrations obtained during the first 30 day operating period after the monitoring system is certified.

(7) For affected EGUs that elect to demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for PM, non-Hg HAP metals, HCl, HF, or Hg through use of CPMS, initial compliance is determined using the average hourly PM, non-Hg HAP metals, HCl, HF, or Hg concentrations obtained during the first 30 day operating period.

(e) *Sorbent Trap Monitoring System Requirements.* For affected EGUs that demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for Hg through use of Hg sorbent trap monitoring system, initial compliance is determined using the average hourly Hg concentrations obtained during the first 30 day operating period.

(f) *Tune-ups.* For affected EGUs subject to work practice standards in Table 3 of this subpart, your initial compliance requirement is to conduct a tune-up of your EGU according to § 63.10021(a)(16)(i) through (vi).

(g) For existing affected sources, you must demonstrate initial compliance no later than 180 days after the compliance date that is specified for your source in § 63.9984 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart.

(h) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011 and [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**] or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(i) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], and you chose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**] or within 3 years after startup of the affected source, whichever is later.

(j) If your new or reconstructed affected source commences construction or reconstruction after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(k) *Low emitting EGU.* Your existing EGU may qualify for low emitting EGU (LEE) status provided that initial performance test data that meet the requirements of § 63.10005(b) and paragraph (l) of this section demonstrate:

(1) With the exception of mercury, emissions less than 50 percent of the appropriate emissions limitation, or

(2) For mercury, emissions less than 10 percent of the mercury emissions limitation or less than 22.0 pounds per year. Only existing affected units may qualify for LEE status for Hg. When qualifying for LEE status for Hg emissions less than 22.0 pounds per year, the affected unit must also demonstrate compliance with the applicable emission limitation.

(3) The following provisions apply in demonstrating that a unit qualifies as a LEE. For all pollutants or surrogates except for Hg, conduct the initial performance tests as described in § 63.10007 but note that the required minimum sampling volume must be increased nominally by a factor of two; follow the instructions in Table 5 to this subpart to convert the test data to the units of the applicable standard. For Hg, you must conduct a 28 to 30 operating day performance test, using Method 30B in appendix A–8 to part 60 of this chapter, to determine Hg concentration. Locate the Method 30B sampling probe tip at a point within the 10 percent centroidal area of the duct at a location that meets Method 1 in appendix A–8 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 28 to 30 day test period. You may not use a pair of sorbent traps to sample the stack gas for more than 10 days. Collect diluent gas data over the corresponding time period, and if preferred for calculation of pounds per year of Hg, stack flow rate data using Method 2 in appendix A–1 to part 60 of this chapter or a certified flow rate monitor and moisture data using Method 4 in appendix A–1 to part 60 of this chapter or a moisture monitor. Record parametric data during each performance test, to establish operating limits, in accordance with the applicable provisions of § 63.10010(k)(3). Calculate the average Hg concentration, in µg/m^3, for the 28 to 30 day performance test, as the arithmetic average of all sorbent trap results. Calculate the average CO_2 or O_2 concentration for the test period. Use the average Hg concentration and diluent gas values to express the performance test results in units of lb of Hg/TBtu, as described in section 6.2.1 of appendix A to this subpart, and, if elected, pounds of Hg per year, using the expected fuel input over a year period. You may also opt to calculate pounds of Hg per year using the average Hg concentration, average stack gas flow rate, average stack gas moisture, and maximum operating hours per year.

(l) Startup and Shutdown default values for calculations. For the purposes of this rule and only during periods of startup or shutdown, use a default diluent gas concentration value of 10.0 percent O_2 or the corresponding fuel-specific CO_2 concentration in calculating emissions in units of lb/MMBtu or lb/TBtu. For calculating emissions in units of lb/MWh or lb/GWh only during startup or shutdown periods, use a nominal electrical production rate equal to 5 percent of rated capacity.

§ 63.10006 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) For solid oil-derived fuel- and coal-fired EGUs using total PM emissions as a surrogate for non-Hg HAP metals emissions and using PM CEMS to measure filterable PM emissions as a surrogate for total PM emissions, you must conduct all applicable performance tests for PM and non-Hg HAP metals emissions during the same compliance test period and under the same process (*e.g.,* fuel) and control device operating conditions according to Table 5 and § 63.10007 at least every 5 years.

(b) For solid oil-derived fuel- and coal-fired EGUs with installed systems that use wet or dry flue gas desulfurization technology using sulfur dioxide (SO_2) emissions as a surrogate for HCl emissions and using SO_2 CEMS to measure SO_2 emissions, you must conduct all applicable performance tests for SO_2 and HCl emissions during the same compliance test period and under the same process (*e.g.,* fuel) and control device operating conditions according to Table 5 and § 63.10007 at least every 5 years.

(c) For affected units meeting the LEE requirements of § 63.1005(k), provided that the unit operates within the operating limits established during the initial performance test, you need only repeat the performance test once every 5 years according to Table 5 and § 63.10007 and conduct fuel sampling and analysis according to Table 6 and § 63.10008 at least every month. However, if the unit fails to operate within the operating limits during any 5 year compliance period, LEE status is lost. If this should occur:

(1) For all pollutants or surrogates except for Hg, you must initiate periodic emission testing, as required in the applicable paragraph(s) of this section, within a six month period.

(2) For Hg, you must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to this subpart, within a one year period.

(d) For solid oil-derived fuel- and coal-fired EGUs without PM CEMS but with PM emissions control devices, you must conduct all applicable performance tests for PM and non-Hg HAP metals emissions during the same compliance test period and under the same process (*e.g.,* fuel) and control device operating conditions according to Table 5 and § 63.10007 at least every year and you must conduct non-Hg HAP metals emissions testing according to Table 5 and § 63.10007 at least every other month.

(e) For solid oil-derived fuel- and coal-fired EGUs without PM CEMS and without PM emissions control devices, you must conduct all applicable performance tests for non-Hg HAP metals emissions according to Table 5 and § 63.10007 at least every month.

(f) For liquid oil-fired EGUs with non-Hg HAP metals control devices, you must conduct all applicable performance tests for individual or total HAP metals emissions according to Table 5 and § 63.10007 at least every other month.

(g) For liquid oil-fired EGUs without non-Hg HAP metals control devices, you must conduct all applicable performance tests for individual or total HAP metals emissions according to Table 5 and § 63.10007 at least every month.

(h) For solid oil-derived fuel- and coal-fired EGUs without SO_2 CEMS but with installed systems that use wet or dry flue gas desulfurization technology, you must conduct all applicable performance tests for SO_2 and HCl emissions during the same compliance test period and under the same process (*e.g.,* fuel) and control device operating conditions according to Table 5 and § 63.10007 at least every year and you must conduct SO_2 emissions testing according to § 63.10007 at least every other month.

(i) For solid oil-derived fuel- and coal-fired EGUs without SO_2 CEMS and without installed systems that use wet or dry flue gas desulfurization technology, you must conduct all applicable performance tests for SO_2 and HCl emissions during the same compliance test period and under the same process (*e.g.,* fuel) and control device operating conditions according to Table 5 and § 63.10007 at least every year and you must conduct HCl emissions testing according to Table 5 and § 63.10007 at least every month.

(j) For solid oil-derived fuel- and coal-fired EGUs without HCl CEMS but with HCl emissions control devices, you must conduct all applicable performance tests for HCl emissions according to Table 5 and § 63.10007 at least every other month.

(k) For solid oil-derived fuel- and coal-fired EGUs without HCl CEMS and without HCl emissions control devices, you must conduct all applicable performance tests for HCl emissions according to Table 5 and § 63.10007 at least every month.

(l) For liquid oil-fired EGUs without HCl and HF CEMS but with HCl and HF emissions control devices, you must conduct all applicable performance tests for HCl and HF emissions according to Table 5 and § 63.10007 at least every other month.

(m) For liquid oil-fired EGUs without HCl and HF CEMS and without HCl and HF emissions control devices, you must conduct all applicable performance tests for HCl and HF emissions according to Table 5 and § 63.10007 at least every month.

(n) Unless you follow the requirements listed in paragraphs (o) through (q) of this section, performance tests required at least every 5 years must be completed within 58 to 62 months after the previous performance test; performance tests required at least every year must be completed no more than 13 months after the previous performance test; performance tests required at least every 2 months must be completed between 52 and 69 days after the previous performance test; and performance tests required at least every month must be completed between 21 and 38 days after the previous performance test.

(o) For EGUs with annual or more frequent performance testing requirements, you can conduct performance stack tests less often for a given pollutant if your performance stack tests for the pollutant for at least 3 consecutive years show that your emissions are at or below 50 percent of the emissions limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions. In this case, you do not have to conduct a performance test for that pollutant for the next 2 years. You must conduct a performance test during the third year and no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (m) of this paragraph.

(p) If your EGU continues to meet the emissions limit for the pollutant, you may choose to conduct performance stack tests for the pollutant every third year if your emissions are at or below the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions, but each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (m) of this paragraph.

(q) If a performance test shows emissions in excess of 50 percent of the emission limit, you must conduct performance tests at the appropriate frequency given in section (c) through (m) of this paragraph for that pollutant until all performance tests over a consecutive 3-year period show compliance.

(r) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to § 63.10007. Each performance tune-up specified in § 63.10007 must be no more than 18 months after the previous performance tune-up.

(s) If you demonstrate compliance with the Hg, individual or total non-Hg HAP metals, HCl, or HF emissions limit based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.10008 for each type of fuel burned. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your EGU. You must still meet all applicable continuous compliance requirements in § 63.10021.

(t) You must report the results of performance tests, performance tune-ups, and fuel analyses within 60 days after the completion of the performance tests, performance tune-ups, and fuel analyses. This report must also verify that the operating limits for your affected EGU have not changed or provide documentation of revised operating parameters established according to § 63.10011 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.10031.

§ 63.10007 What methods and other procedures must I use for the performance tests?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that has the highest content of chlorine, fluorine, non-Hg HAP metals, and Hg, and you must demonstrate initial compliance and establish your operating limits based on these tests. These requirements could result in the need to conduct more than one performance test. Moreover, should you desire to have differing operating limits which correspond to loads other than maximum normal operating load, you should conduct testing at those other loads to determine those other operating limits. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 of this subpart.

(d) For performance testing that does not involve CMS or a sorbent trap monitoring system, you must conduct three separate test runs for each performance test required, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 to this subpart. For performance testing that involves CMS or a sorbent trap monitoring system, compliance shall be determined as described in § 63.10005(d) and (e).

(e) To determine compliance with the emission limits, you must use the F–Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, Appendix A–7 of this chapter to convert the measured PM concentrations, the measured HCl and HF concentrations, the measured SO_2 concentrations, the measured individual and total non-Hg HAP metals concentrations, and the measured Hg concentrations that result from the initial performance test to pounds per million Btu (lb/MMBtu) (pounds per trillion Btu, lb/TBtu, for Hg) heat input emission rates using F-factors.

(f) Performance tests shall be conducted under such conditions as the EPA Administrator specifies to the owner or operator based on representative performance of the affected source for the period being tested. Upon request, the owner or operator shall make available to the EPA Administrator such records as may be necessary to determine the conditions of performance tests.

§ 63.10008 What fuel analyses and procedures must I use for the performance tests?

(a) You must conduct performance fuel analysis tests according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. You are not required to conduct fuel analyses for fuels used only for startup, unit shutdown, or transient flame stability purposes.

(b) You must develop and submit a site-specific fuel analysis plan to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section.

(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to demonstrate compliance.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each EGU.

(ii) For each fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine, fluorine, non-Hg HAP metals, or Hg.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal 1-hour intervals during the testing period.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a depth of 18 inches. You must insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break sample pieces larger than 3 inches into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (Hg, HAP metals, and/or chlorine) in units of lb/MMBtu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart.

§ 63.10009 May I use emission averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.9991 for PM, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis, if you have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control), you may demonstrate compliance by emission averaging among the existing EGUs in the same subcategory, if your averaged emissions for such EGUs are equal to or less than the applicable emission limit, according to the procedures in this section.

(b) Separate stack requirements. For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average PM, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (c), (d), (e), (f), and (g) of this section.

(c) For each existing EGU in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on [*THE DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* ***FEDERAL REGISTER***] or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on [*THE DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* ***FEDERAL REGISTER***].

(d) The averaged emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified in § 63.9984.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum normal operating load of each EGU and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1 of this section to demonstrate that the PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from all existing units participating in the emissions averaging option do not exceed the emission limits in Table 2 to this subpart.

$$\text{Ave Weighted Emissions} = \sum_{i=1}^{n}(Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq. 1)}$$

Where:

Ave Weighted Emissions = Average weighted emissions for PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Er = Emissions rate (as determined during the most recent performance test, according to Table 5 to this subpart) for PM, HF, HCl, non-Hg HAP metals, or Hg or by fuel analysis for Cl, F, non-Hg HAP metals, or Hg as calculated by the applicable equation in § 63.10011(c) for unit, i, for PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input, and the EGU generates steam for purposes other than generating electricity, you may use Equation 2 of this section as an alternative to using Equation 1 of this section to demonstrate that the PM, HF, HCl, non-Hg HAP metals, and Hg emissions from all existing units participating in the emissions averaging option do not exceed the emission limits in Table 2 to this subpart.

$$\text{Ave Weighted Emissions} = \sum_{i=1}^{n}(Er \times Sm \times Cfi) \div \sum_{i=1}^{n} Sm \times Cfi \qquad \text{(Eq. 2)}$$

Where:

Ave Weighted Emissions = Average weighted emission level for PM, HF, HCl, non-Hg HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Er = Emissions rate (as determined during the most recent performance test, according to Table 5 to this subpart) for PM, HF, HCl, non-Hg HAP metals, or Hg or by fuel analysis for Cl, F, non-Hg HAP metals, or Hg as calculated by the applicable equation in § 63.10011(c)) for unit, i, for PM, HCl, HF, HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Sm = Maximum steam generation by unit, i, in units of pounds.

Cf = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

n = Number of units participating in the emissions averaging option.

(f) You must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.9984.

(1) For each calendar month, you must use Equation 3 of this section to calculate the monthly average weighted emission rate using the actual heat capacity for each existing unit participating in the emissions averaging option.

$$\text{Ave Weighted Emissions} = \sum_{i=1}^{n}(Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3)}$$

Where:

Ave Weighted Emissions = Monthly average weighted emission level for PM, HCl, HF, non-Hg HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Er = Emissions rate, (as determined during the most recent performance test, according to Table 5 to this subpart) for PM, HCl, HF, non-Hg HAP metals, or Hg or by fuel analysis for Cl, F, non-Hg HAP metals, or Hg as calculated by the applicable equation in § 63.10011(c)) for unit, i, for PM, HCl, HF, non-Hg HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Hb = The average heat input for each calendar month of EGU, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3 of this section to calculate the monthly weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

$$\text{Ave Weighted Emissions} = \sum_{i=1}^{n}(Er \times Sa \times Cfi) \div \sum_{i=1}^{n} Sa \times Cfi \qquad \text{(Eq. 4)}$$

Where:

Ave Weighted Emissions = Monthly average weighted emission level for PM, HCl, HF, HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Er = Emissions rate, (as determined during the most recent performance test, as calculated according to Table 5 to this subpart) for PM, HCl, HF, non-Hg HAP metals, or Hg or by fuel analysis for Cl, F, and non-Hg HAP metals, or Hg as calculated by the applicable equation in § 63.10011(c)) for unit, i, for PM, HCl, HF, non-Hg HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Sa = Actual steam generation for each calendar month by EGU, i, in units of pounds.

Cf = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

n = Number of units participating in the emissions averaging option.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the monthly

average weighted emission rate determined under paragraph (f)(1) or (2) of this section. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current month and the previous 11 months.

$$\text{Eavg} = \sum_{i=1}^{n} \text{ERi} \div 12 \qquad \text{(Eq. 5)}$$

Where:

Eavg = 12-month rolling average emissions rate, (lb/MMBtu heat input; lb/TBtu for Hg).
ERi = Monthly weighted average, for month "i" (lb/MMBtu (lb/TBtu for Hg) heat input)(as calculated by (f)(1) or (2)).

(g) You must develop, and submit to the applicable regulatory authority for review and approval upon request, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing EGUs in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**] and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, the owner or operator must identify each EGU;

(iv) The test plan for the measurement of PM, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in § 63.10007;

(v) The operating parameters to be monitored for each control system or device consistent with § 63.9991 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to § 63.10010, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the applicable regulatory authority, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating conditions.

(3) The regulatory authority shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable regulatory authority shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategory.

(h) *Common stack requirements.* For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to paragraph (h) of this section, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in § 63.10007 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of equation 6.

$$\text{En} = \sum_{i=1}^{n} (\text{ELi} \times \text{Hi}) \div \sum_{i=1}^{n} \text{Hi} \qquad \text{(Eq. 6)}$$

Where:

En = HAP emissions limit, lb/MMBtu (lb/TBtu for Hg), ppm, or ng/dscm.
ELi = Appropriate emissions limit from Table 2 to this subpart for unit i, in units of lb/MMBtu (lb/TBtu for Hg), ppm, or ng/dscm.
Hi = Heat input from unit i, MMBtu.
n = Number of units.

(2) Conduct performance tests according to procedures specified in § 63.10007 in the common stack. If affected units from nonaffected units vent to the common stack,the units from nonaffected units must be shut down or vented to a different stack during the performance test or each affected and each nonaffected unit must meet the most stringent emissions limit; and

(3) Meet the applicable operating limit specified in § 63.10021 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (h) of this section may be treated as a single stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) In some cases, existing affected units may exhaust through a common stack configuration or may include a bypass stack. Emission monitoring system installation provisions for possible stack configurations are as follows.

(1) *Single Unit-Single Stack Configuration.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, the owner or operator shall install CEMS and sorbent trap monitoring systems in accordance

with the applicable performance specification or Appendix A to this subpart.

(2) *Unit Utilizing Common Stack with Other Affected Unit(s).* When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, the owner or operator shall either:

(i) Install CEMS and sorbent trap monitoring systems described in this section in the duct to the common stack from each unit; or

(ii) Install CEMS and sorbent trap monitoring systems described in this section in the common stack.

(3) *Unit Utilizing Common Stack with Non-affected Units.* When one or more affected units shares a common stack with one or more non-affected units, the owner or operator shall either:

(i) Install CEMS and sorbent trap monitoring systems described in this section in the duct to the common stack from each affected unit; or

(ii) Install CEMS and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(4) *Unit with a Main Stack and a Bypass Stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, the owner and operator shall install CEMS and the monitoring systems described in paragraph 2.1 of this section on both the main stack and the bypass stack.

(5) *Unit with Multiple Stack or Duct Configuration.* If the flue gases from an affected unit either: are discharged to the atmosphere through more than one stack; or are fed into a single stack through two or more ducts and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:

(i) Install CEMS and sorbent trap monitoring systems described in this section in each of the multiple stacks; or

(ii) Install CEMS and sorbent trap monitoring systems described in this section in each of the ducts that feed into the stack.

(b) If you use an oxygen (O_2) or carbon dioxide (CO_2) continuous emissions monitoring system (CEMS), install, operate, and maintain a CEMS for oxygen or carbon dioxide according to the procedures in paragraphs (b)(1) through (5) of this section by the compliance date specified in § 63.9984. The oxygen or carbon dioxide shall be monitored at the same location as the other pollutant CEMS, i.e., at the outlet of the EGU. Alternatively, an owner or operator may install, certify, maintain, operate and quality assure the data from an O_2 or CO_2 CEMS according to Appendix A of this subpart in lieu of the procedures in paragraphs (a)(1) through (a)(3) of this section.

(1) Install, operate, and maintain the O_2 or CO_2 CEMS according to the applicable procedures under Performance Specification (PS) 3 of 40 CFR part 60, Appendix B; and according to the applicable procedures under Quality Assurance Procedure 1 of 40 CFR part 60, Appendix F; and according to the site-specific monitoring plan developed according to § 63.10000(d).

(2) Conduct a performance evaluation of the CEMS according to the requirements in § 63.8 and according to PS 3 of 40 CFR part 60, Appendix B.

(3) Design and operate the CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Reduce the CEMS data as specified in § 63.8(g)(2) and (4).

(5) Consistent with § 63.10020, calculate and record a 30 boiler operating day rolling average emissions rate on a daily basis. Daily, calculate a new 30 boiler operating day rolling average emissions rate as the average of all of the hourly oxygen emissions data for the preceding 30 boiler operating days.

(c) If you use an HCl CEMS, install, operate, and maintain a CEMS for HCl according to the procedures in paragraphs (c)(1) through (5) of this section by the compliance date specified in § 63.9984. The HCl shall be monitored at the outlet of the EGU.

(1) Install, operate, and maintain the CEMS according to the applicable procedures under Performance Specification (PS) 15 or 6 of 40 CFR part 60, Appendix B; and according to the applicable procedures under Quality Assurance Procedure 1 of 40 CFR part 60, Appendix F; and according to the site-specific monitoring plan developed according to § 63.10000(d).

(2) Conduct a performance evaluation of the CEMS according to the requirements in § 63.8 and according to PS 15 or 6 of 40 CFR part 60, Appendix B.

(3) Design and operate the CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Reduce the CEMS data as specified in § 63.8(g)(2) and (4).

(5) Consistent with § 63.10020, calculate and record a 30 boiler operating day rolling average emissions rate on a daily basis. Daily, calculate a new 30 boiler operating day rolling average emissions rate as the average of all of the hourly HCl emissions data for the preceding 30 boiler operating days.

(d) If you use an HF CEMS, install, operate, and maintain a CEMS for HF according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.9984. The HF shall be monitored at the outlet of the EGU.

(1) Install, operate, and maintain the CEMS according to the applicable procedures under Performance Specification (PS) 15 of 40 CFR part 60, Appendix B; and according to the applicable procedures under Quality Assurance Procedure 1 of 40 CFR part 60, Appendix F; and according to the site-specific monitoring plan developed according to § 63.10000(d).

(2) Conduct a performance evaluation of the CEMS according to the requirements in § 63.8 and according to PS 15 or 6 of 40 CFR part 60, Appendix B.

(3) Design and operate the CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Reduce the CEMS data as specified in § 63.8(g)(2) and (4).

(5) Consistent with § 63.10020, calculate and record a 30 boiler operating day rolling average emissions rate on a daily basis. Daily, calculate a new 30 boiler operating day rolling average emissions rate as the average of all of the hourly HF emissions data for the preceding 30 boiler operating days.

(e) If you use an SO_2 CEMS, install, operate, and maintain a CEMS for SO_2 according to the procedures in paragraphs (e)(1) through (5) of this section by the compliance date specified in § 63.9984. The SO_2 shall be monitored at the outlet of the EGU. Alternatively, for an affected source that is also subject to the SO_2 monitoring requirements of Part 75 of this chapter, the or operator may install, certify, maintain, operate and quality assure the data from an SO_2 CEMS according to Part 75 of this chapter in lieu of the procedures in paragraphs (g)(1) through (g)(3) of this section with the additional provisions of paragraph (g)(6).

(1) Install, operate, and maintain the CEMS according to the applicable procedures under Performance Specification (PS) 2 of 40 CFR part 60, Appendix B; and according to the applicable procedures under Quality Assurance Procedure 1 of 40 CFR part 60, Appendix F; and according to the site-specific monitoring plan developed according to § 63.10000(d).

(2) Conduct a performance evaluation of the CEMS according to the

requirements in § 63.8 and according to PS 2 or 6 of 40 CFR part 60, Appendix B.

(3) Design and operate the CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Reduce the CEMS data as specified in § 63.8(g)(2) and (4).

(5) Consistent with § 63.10020, calculate and record a 30 boiler operating day rolling average emissions rate on a daily basis. Daily, calculate a new 30 boiler operating day rolling average emissions rate is calculated as the average of all of the hourly SO_2 emissions data for the preceding 30 boiler operating days.

(6) When electing to use a Part 75 certified SO_2 CEMS to meet the requirements of this subpart, you must additionally meet the provisions listed in paragraphs (6)(i) through (6)(iii) below.

(i) You must perform the 7-day calibration error test required in appendix A to Part 75 on the SO_2 CEMS whether or not it has a span of 50 ppm or less.

(ii) You must perform the linearity check test required in appendix A to Part 75 on the SO_2 CEMS whether or not it has a span of 30 ppm or less.

(iii) The initial and quarterly linearity checks required under appendix A and appendix B of Part 75 must include a calibration gas (at a fourth level, if necessary) nominally at a concentration level equivalent to the applicable emission limit.

(f) If you use a Hg CEMS or a sorbent trap monitoring system for Hg, install, operate, and maintain the monitoring system in accordance with Appendix A to this subpart.

(g) If you use a PM CEMS, install, operate, and maintain a CEMS for PM according to the procedures in paragraphs (g)(1) through (6) of this section by the compliance date specified in § 63.9984. The PM shall be monitored at the outlet of the EGU.

(1) Install, operate, and maintain according to the applicable procedures under Performance Specification (PS) 11 of 40 CFR part 60, Appendix B; and according to the applicable procedures under Quality Assurance Procedure 2 of 40 CFR part 60, Appendix F; and according to the site-specific monitoring plan developed according to § 63.10000(d).

(2) Conduct a performance evaluation of the CEMS according to the requirements in § 63.8 and according to PS 11 of 40 CFR part 60, Appendix B.

(3) Design and operate the CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Reduce the CEMS data as specified in § 63.8(g)(2) and (4).

(5) Consistent with § 63.10020, calculate and record a 30 boiler operating-day rolling average emissions rate on a daily basis. Daily, calculate a new 30 boiler operating day rolling average emissions rate is calculated as the average of all of the hourly particulate emissions data for the preceding 30 boiler operating days.

(h) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (h)(1) through (3) of this section by the compliance date specified in § 63.9984.

(1) Install, operate, and maintain each CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.10000(d) of this subpart and the design criteria and quality assurance and quality control procedures specified in paragraphs (h)(1) through (3) of this section. You may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (h)(1) through (3) of this section in your site-specific monitoring plan.

(2) Design and operate the CPMS to collect and record data measurements at least once every 15 minutes (see also § 63.10020), to reduce the measured values to a hourly averages or other appropriate period (e.g., instantaneous alarms) for calculating operating values in terms of the applicable averaging period, and to meet the specific CPMS requirements given in (i) through (v) of this section.

(i) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in (i)(A) through (D) of this section.

(A) Install the flow sensor and other necessary equipment in a position that provides a representative flow.

(B) Use a flow sensor with a measurement sensitivity of no greater than 2 percent of the expected flow rate.

(C) Minimize the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(D) Conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(ii) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in (ii)(A) through (F) of this section.

(A) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (e.g., PM scrubber pressure drop).

(B) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.

(C) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(D) Perform checks at least once each boiler operating day to ensure pressure measurements are not obstructed (e.g., check for pressure tap pluggage daily).

(E) Conduct a performance evaluation of the pressure measurement monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(F) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in your monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(iii) If you have an operating limit that requires a total secondary electric power monitoring system for an electrostatic precipitator (ESP), you must meet the requirements in (iii)(A) through (B) of this section.

(A) Install sensors to measure (secondary) voltage and current to the precipitator plates.

(B) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(iv) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in (iv)(A) through (B) of this section.

(A) Install each system in a position that provides a representative measurement of the total sorbent injection rate.

(B) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(v) If you have an operating limit that requires the use of a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate a bag leak detection system as specified in (v)(A) through (F) of this section.

(A) Install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(B) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(C) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA–454/R–98–015 (incorporated by reference, see § 63.14).

(D) Use a bag leak detection system equipped with a device to continuously record the output signal from the sensor.

(E) Use a bag leak detection system equipped with a system that will alert when an increase in relative PM emissions over a preset level is detected. The alarm must be located where it can be detected and recognized easily by an operator.

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

(3) Conduct the CPMS equipment performance evaluations as specified in your site-specific monitoring plan.

§ 63.10011 How do I demonstrate initial compliance with the emission limits and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.10007, paragraph (c) of this section, and Tables 5 and 7 to this subpart.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.10007, Table 7 to this subpart, and paragraph (c)(6) of this section, as applicable. You must also conduct fuel analyses according to § 63.10008 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (5) of this section, as applicable.

(1) You must establish the maximum chlorine fuel input (C_{input}) during the initial performance testing according to the procedures in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your EGU that has the highest content of chlorine.

(ii) During the performance testing for HCl, you must determine the fraction of the total heat input for each fuel type burned (Q_i) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (C_i).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$\text{Clinput} = \sum_{i=1}^{n} (\text{Ci} \times \text{Qi}) \qquad \text{(Eq. 7)}$$

Where:

Clinput = Maximum amount of chlorine entering the EGU through fuels burned in units of lb/MMBtu.
Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to § 63.10008, in units of lb/MMBtu.
Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.
n = Number of different fuel types burned in your EGU for the mixture that has the highest content of chlorine.

(2) You must establish the maximum Hg fuel input level (Mercury_{input}) during the initial performance testing using the procedures in paragraphs (c)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your EGU that has the highest content of Hg.

(ii) During the compliance demonstration for Hg, you must determine the fraction of total heat input for each fuel burned (Q_i) based on the fuel mixture that has the highest content of Hg, and the average Hg concentration of each fuel type burned (HG_i).

(iii) You must establish a maximum Hg input level using Equation 8 of this section.

$$\text{Mercuryinput} = \sum_{i=1}^{n} (\text{HGi} \times \text{Qi}) \qquad \text{(Eq. 8)}$$

Where:

Mercuryinput = Maximum amount of Hg entering the EGU through fuels burned in units of lb/TBtu.
HGi = Arithmetic average concentration of Hg in fuel type, i, analyzed according to § 63.10008, in units of lb/TBtu.
Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest Hg content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.
n = Number of different fuel types burned in your EGU for the mixture that has the highest content of Hg.

(3) You must establish the maximum non-Hg HAP metals fuel input level (HAP metal_{input}) during the initial performance testing using the procedures in paragraphs (c)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your EGU that has the highest content of non-Hg HAP metals.

(ii) During the compliance demonstration for non-Hg HAP metals, you must determine the fraction of total heat input for each fuel burned (Q_i) based on the fuel mixture that has the highest content of non-Hg HAP metals, and the average non-Hg HAP metals concentration of each fuel type burned (HAP metal_i).

(iii) You must establish a maximum non-Hg HAP metal input level using Equation 9 of this section.

$$\text{HAP metalinput} = \sum_{i=1}^{n} (\text{HAP metali} \times \text{Qi}) \qquad \text{(Eq. 9)}$$

Where:

HAP metalinput = Maximum amount of non-Hg HAP metals entering the EGU through fuels burned in units of lb/MMBtu.
HAP metali = Arithmetic average concentration of non-Hg HAP metals in fuel type, i, analyzed according to § 63.10008, in units of lb/MMBtu.
Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that

has the highest non-Hg HAP metal content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest content of non-Hg HAP metals.

(4) You must establish the maximum fluorine fuel input (F_{input}) during the initial performance testing according to the procedures in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your EGU that has the highest content of fluorine.

(ii) During the performance testing for HF, you must determine the fraction of the total heat input for each fuel type burned (Q_i) based on the fuel mixture that has the highest content of fluorine, and the average fluorine concentration of each fuel type burned (F_i).

(iii) You must establish a maximum fluorine input level using Equation 10 of this section.

$$\text{Flinput} = \sum\nolimits_{i=1}^{n} (\text{Fi} \times \text{Qi}) \qquad \text{(Eq. 10)}$$

Where:

Fl input = Maximum amount of fluorine entering the EGU through fuels burned in units of lb/MMBtu.

Fi = Arithmetic average concentration of fluorine in fuel type, i, analyzed according to § 63.10008, in units of lb/MMBtu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest content of fluorine.

(6) You must establish parameter operating limits according to paragraphs (c)(4)(i) through (v) of this section.

(i) For a wet PM scrubber, you must establish the minimum liquid flow rate and pressure drop as defined in § 63.10042, as your operating limits during the three-run performance test. If you use a wet PM scrubber and you conduct separate performance tests for PM, non-Hg HAP metals, or Hg emissions, you must establish one set of minimum liquid flow rate and pressure drop operating limits. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the highest minimum hourly average values established during the performance tests.

(ii) For a wet acid gas scrubber, you must establish the minimum liquid flow rate and pH as defined in § 63.10042, as your operating limits during the three-run performance test. If you use a wet acid gas scrubber and you conduct separate performance tests for HCl, HF, or SO_2 emissions, you must establish one set of minimum liquid flow rate and pH operating limits. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pH operating limits at the highest minimum hourly average values established during the performance tests.

(iii) For an electrostatic precipitator, you must establish the minimum hourly average secondary voltage and secondary amperage and calculate the total secondary power input as measured during the three-run performance test and as defined in § 63.10042, as your operating limit.

(iv) For a dry scrubber or dry sorbent injection (DSI) system, you must establish the minimum hourly average sorbent injection rate for each sorbent, as measured during the three-run performance test and as defined in § 63.10042, as your operating.

(v) The operating limit for EGUs with fabric filters that choose to demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.10010, and that the sum duration of bag leak detection system alarms does not exceed 5 percent of the process operating time during a 6-month period.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.10008 and follow the procedures in paragraphs (c)(1) through (7) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your EGU that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided z-statistic test described in Equation 11 of this section.

$$\text{P90} = \text{mean} + (\text{SD} \times \text{t}) \qquad \text{(Eq. 11)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in lb/MMBtu (lb/TBtu for Hg).

mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.10008, in units of lb/MMBtu (lb/TBtu for Hg).

SD = Standard deviation of the pollutant concentration in the fuel samples analyzed according to § 63.10008, in units of lb/MMBtu (lb/TBtu for Hg).

t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your EGU using Equation 12 of this section must not exceed the applicable emission limit for HCl.

$$\text{HCl} = \sum_{i=1}^{n} (\text{Ci90} \times \text{Qi} \times 1.028) \qquad \text{(Eq. 12)}$$

Where:

HCl = HCl emissions rate from the EGU in units of lb/MMBtu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of lb/MMBtu as calculated according to Equation 12 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for Hg, the Hg emissions rate that you calculate for your EGU using Equation 13 of this section must not exceed the applicable emission limit for Hg.

$$\text{Mercury} = \sum_{i=1}^{n} (\text{HGi90} \times \text{Qi}) \qquad \text{(Eq. 13)}$$

Where:

Mercury = Hg emissions rate from the EGU in units of lb/TBtu.

HGi90 = 90th percentile confidence level concentration of Hg in fuel, i, in units of lb/TBtu as calculated according to Equation 8 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest Hg content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest Hg content.

(5) To demonstrate compliance with the applicable emission limit for non-Hg HAP metals, the non-Hg HAP metal emissions rate that you calculate for your EGU using Equation 14 of this

section must not exceed the applicable emissions limit for non-Hg HAP metals.

$$HAPmetals = \sum_{i=1}^{n} (HAPmetalsi90 \times Qi) \qquad (Eq.\ 14)$$

Where:

HAPmetals = Non-Hg HAP metals emission rate from the EGU in units of lb/MMBtu.

HAPmetalsi90 = 90th percentile confidence level concentration of non-Hg HAP metals in fuel, i, in units of lb/MMBtu as calculated according to Equation 9 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest non-Hg HAP metals content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest non-Hg HAP metals content.

(6) To demonstrate compliance with the applicable emission limit for HF, the HF emissions rate that you calculate for your EGU using Equation 15 of this section must not exceed the applicable emission limit for HF.

$$HF = \sum_{i=1}^{n} (Fi90 \times Qi \ \times 1.053) \qquad (Eq.\ 15)$$

Where:

HF = HF emissions rate from the EGU in units of lb/MMBtu.

Fi90 = 90th percentile confidence level concentration of fluorine in fuel type, i, in units of lb/MMBtu as calculated according to Equation 7 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of fluorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest content of fluorine.

1.053 = Molecular weight ratio of HF to fluorine.

(d) For units combusting coal or solid oil-derived fuel and electing to use PM as a surrogate for non-Hg HAP metals, you must install, certify, and operate PM CEMS in accordance with Performance Specification (PS) 11 in Appendix B to 40 CFR part 60, and to perform periodic, ongoing quality assurance (QA) testing of the CEMS according to QA Procedure 2 in Appendix F to 40 CFR Part 60. You must determine an operating limit (PM concentration in mg/dscm) during performance testing for initial PM compliance. The operating limit will be the average of the PM filterable results of the three Method 5 performance test runs. To determine continuous compliance, the hourly average PM concentrations will be averaged on a rolling 30 boiler operating day basis. Each 30 boiler operating day average would have to meet the PM operating limit.

(e) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.10030(e).

(f) If you are a LEE, the results of your initial performance test demonstrate your initial compliance.

Continuous Compliance Requirements

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions 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.

(d) Except for periods of monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (17) of this section.

(1) Following the date on which the initial performance test is completed or is required to be completed under §§ 63.7 and 63.10005, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Table 4 to this subpart at any time. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.10031(c), you must keep records of the type and amount of all fuels burned in each EGU during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would either result in lower emissions of HCl, HF, SO_2, non-Hg HAP metals, or Hg, than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel input of chlorine, fluorine, sulfur, non-Hg HAP metals, or Hg than the maximum values calculated during the last performance tests (if you demonstrate compliance through performance stack testing).

(3) If you demonstrate compliance with an applicable HCl emissions limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the HCl emissions rate using Equation 15 of § 63.10011 according to paragraphs (a)(3)(i) through (iii) of this section.

(i) You must determine the chlorine concentration for any new fuel type in units of lb/MMBtu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.10008(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emissions rate from your EGU under these new conditions using Equation 15 of § 63.10011. The recalculated HCl emissions rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emissions limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.10011. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.10011 are higher than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.10007 to demonstrate that the HCl emissions do not exceed the emissions limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.10011(b).

(5) If you are a liquid oil-fired EGU and demonstrate compliance with an applicable individual Hg emissions limit (rather than the total HAP metal emission limit) through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the Hg emissions rate using Equation 11 of § 63.10011 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section.

(i) You must determine the Hg concentration for any new fuel type in units of lb/TBtu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.10008(b).

(ii) You must determine the new mixture of fuels that will have the highest content of Hg.

(iii) Recalculate the Hg emissions rate from your EGU under these new conditions using Equation 11 of § 63.10011. The recalculated Hg emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable Hg emissions limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum Hg input using Equation 8 of § 63.10011. If the results of recalculating the maximum Hg input using Equation 8 of § 63.10011 are higher than the maximum Hg input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.10007 to demonstrate that the Hg emissions do not exceed the emissions limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.10011(b).

(7) If you are a liquid oil-fired EGU and demonstrate compliance with an applicable HAP metals emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the HAP metals emission rate using Equation 14 of § 63.10011 according to the procedures specified in paragraphs (a)(7)(i) through (iii) of this section.

(i) You must determine the HAP metals concentration for any new fuel type in units of lb/MMBtu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.10008(b).

(ii) You must determine the new mixture of fuels that will have the highest content of HAP metals.

(iii) Recalculate the HAP metals emission rate from your EGU under these new conditions using Equation 14 of § 63.10011. The recalculated HAP metals emission rate must be less than the applicable emissions limit.

(8) If you demonstrate compliance with an applicable HAP metals emissions limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum HAP metals input using Equation 9 of § 63.10011. If the results of recalculating the maximum Hg input using Equation 9 of § 63.10011 are higher than the maximum HAP metals input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.10007 to demonstrate that the HAP metal emissions do not exceed the emissions limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.10011(b).

(9) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the sum duration of alarms does not exceed 5 percent of the process operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

(10) If you are required to install a CEMS according to § 63.10010(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.

(i) You must continuously monitor oxygen according to §§ 63.10010(a) and 63.10020.

(ii) Keep records of oxygen levels according to § 63.10032(b).

(11) The owner or operator of an affected source using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (a)(11)(i) through (iv) of this section.

(i) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of § 60.13 of 40 CFR, Performance Specification 11 in Appendix B of 40 CFR part 60, and procedure 2 in Appendix F of 40 CFR part 60.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 in Appendix B of 40 CFR part 60, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the CEMS and conducting performance tests using

Method 5 or 5D of Appendix A–3 of 40 CFR part 60.

(iii) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in Appendix F of this chapter. Relative Response Audits must be performed annually and Response Correlation Audits must be performed every 3 years.

(iv) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*). Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(v) Within 60 days after the date of completing each CEMS performance evaluation test, as defined in § 63.2 and required by this subpart, you must submit the relative accuracy test audit data electronically into EPA's Central Data Exchange by using the Electronic Reporting Tool as mentioned in paragraph (11)(iv) of this section. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(vi) All reports required by this subpart not subject to the requirements in paragraphs (11)(iv) and (v) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (11)(iv) and (v) of this section in paper format.

(12) The owner or operator of an affected source using a CEMS measuring HCl emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (a)(12)(i) through (iii) of this section.

(i) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of § 60.13 of 40 CFR, Performance Specifications 6 or 15 in Appendix B of 40 CFR part 60, and procedure 2 in Appendix F of 40 CFR part 60.

(ii) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 1 in Appendix F of 40 CFR part 60.

(13) The owner or operator of an affected source using a CEMS measuring SO_2 emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (a)(13)(i) through (iii) of this section.

(i) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of § 60.13 of 40 CFR part 60, Performance Specification 2 or 6 in Appendix B of 40 CFR part 60, and procedure 1 in Appendix F of 40 CFR part 60.

(ii) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 1 in Appendix F of 40 CFR part 60.

(14) The owner or operator of an affected source using a CEMS measuring Hg emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (a)(14)(i) through (iii) of this section.

(i) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of Appendix A of this subpart.

(ii) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 5 in Appendix F of 40 CFR part 60.

(15) As an alternative to measuring Hg emissions using Hg CEMS, the owner or operator of an affected source using a sorbent trap monitoring system to meet requirements of this subpart shall install, certify, operate, and maintain the sorbent trap monitoring system in accordance with Appendix A to this subpart.

(16) You must conduct a performance tune-up of the EGU to demonstrate continuous compliance as specified in paragraphs (a)(16)(i) through (a)(16)(vii) of this section.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, but you must inspect each burner at least once every 18 months);

(ii) Inspect the flame pattern, as applicable, and make any adjustments to the burner necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly;

(iv) Optimize total emissions of CO and NO_X. This optimization should be consistent with the manufacturer's specifications, if available;

(v) Measure the concentration in the effluent stream of CO and NO_X in ppm, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made); and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(16)(vi)(A) through (C) of this section,

(A) The concentrations of CO and NO_X in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after the adjustments of the EGU;

(B) A description of any corrective actions taken as a part of the combustion adjustment; and

(C) The type and amount of fuel used over the 12 months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period.

(vii) After December 31, 2011, and within 60 days after the date of completing each performance tune-up conducted to demonstrate compliance with this subpart, you must submit a notice of completion of the performance tune-up to EPA by successfully submitting the data electronically into an EPA database.

(17) For LEEs, the results of your initial and subsequent emissions tests, along with records of your fuel analyses, demonstrate your continuous compliance and continued eligibility as a LEE.

(i) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*). Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(ii) Within 60 days after the date of completing each CEMS performance evaluation test, as defined in 63.2 and required by this subpart, you must submit the relative accuracy test audit data electronically into EPA's Central Data Exchange by using the Electronic

Reporting Tool as mentioned in paragraph (17)(i) of this section. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(iii) All reports required by this subpart not subject to the requirements in paragraphs (17)(i) and (ii) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (17)(i) and (ii) of this section in paper format.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 to this subpart that apply to you. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in § 63.10031.

(c) Consistent with § 63.10010, § 63.10020, and your site-specific monitoring plan, you must determine the 3-hour rolling average of the CPMS data collected for all periods the process is operating.

§ 63.10022 How do I demonstrate continuous compliance under the emission averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (8) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.10009(f) and (g);

(2) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber for PM control, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test;

(3) For each existing unit participating in the emissions averaging option that is equipped with a fabric filter but without PM CEMS, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test;

(4) For each existing unit participating in the emissions averaging option that is equipped with dry sorbent injection, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test;

(5) For each existing unit participating in the emissions averaging option that is equipped with an ESP, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test;

(6) For each existing unit participating in the emissions averaging option that is equipped with an ESP, maintain the monthly fuel content values at or below the operating limits established during the most recent performance test;

(7) For each existing unit participating in the emissions averaging option that has an approved alternative operating plan, maintain the 3-hour average parameter values at or below the operating limits established in the most recent performance test.

(8) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (8) of this section is a deviation.

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], you must submit an Initial Notification not later than 120 days after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**].

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.10011(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each initial compliance demonstration, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, 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). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (6), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing and fuel analysis; performance testing with operational limits (e.g., CEMS for surrogates or CPMS); CEMS; or sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, 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.

(7) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification of compliance and must be signed by a responsible official:

(i) "This EGU complies with the requirement in § 63.10021(a)(16)(i) through (vi)."

§ 63.10031 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(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 § 63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in § 63.9984.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.9984.

(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 is the first date following 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 (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (9) 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) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(5) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every three years consistent with § 63.10006(o) or (p), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 50 percent emission limit threshold required in § 63.10006(o) or (p), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(6) A signed statement indicating that you burned no new types of fuel. Or, if you did burn a new type of fuel, you must submit the calculation of chlorine input, using Equation 7 of § 63.10011, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 15 of § 63.10011 that demonstrates that your source is still meeting the emission limit for HCl emissions (for EGUs that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of Hg input, using Equation 8 of § 63.10011, that demonstrates that your source is still within its maximum Hg input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of Hg emission rate using Equation 11 of § 63.10011 that demonstrates that your source is still meeting the emission limit for Hg emissions (for EGUs that demonstrate compliance through fuel analysis).

(7) If you wish to burn a new type of fuel and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.10011 or the maximum Hg input operating limit using Equation 8 of § 63.10011, you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(8) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(9) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(10) Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to § 63.10021(a)(16)(i) through (vi). Include the date of the most recent burner inspection if it was not done annually and was delayed until the next scheduled unit shutdown.

(d) For each deviation from an emission 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 limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (4) of this section.

(1) The total operating time of each affected source during the reporting period.

(2) A description of the deviation and which emission limit or operating limit from which you deviated.

(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(4) A copy of the test report if the annual performance test showed a deviation from the emission limits.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in paragraphs (e)(1) through (12) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.10000(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) 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.

(5) 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.

(6) An analysis 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.

(7) A summary of the total duration of CMSs 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.

(8) An identification of each parameter that was monitored at the affected source for which there was a deviation.

(9) A brief description of the source for which there was a deviation.

(10) A brief description of each CMS for which there was a deviation.

(11) The date of the latest CMS certification or audit for the system for which there was a deviation.

(12) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f) 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 pursuant to Table 9 to this subpart 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 limit, operating limit, or work practice requirement in this subpart, 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 permit authority.

(g) In addition to the information required in § 63.9(h)(2), your notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(1) "This facility complies with the requirements in § 63.10021(a)(10) to conduct an annual performance test of the unit".

(2) "No secondary materials that are solid waste were combusted in any affected unit."

(h)(1) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*). Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(2) Within 60 days after the date of completing each CEMS performance evaluation test, as defined in 63.2 and required by this subpart, you must submit the relative accuracy test audit data electronically into EPA's Central Data Exchange by using the Electronic Reporting Tool as mentioned in paragraph (h)(1) of this section. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(3) All reports required by this subpart not subject to the requirements in paragraphs (h)(1) and (2) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (h)(1) and (2) of this section in paper format.

(i) If you had a malfunction during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.10000(b), including actions taken to correct a malfunction.

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) through (2) 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) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in § 63.10(b)(2)(viii).

(b) For each CEMS and CPMS, 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 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits such as pressure drop and pH to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (5) of this section.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), you must keep a record which documents how the fuel satisfies the requirements of the petition process.

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.10011, that were done to demonstrate continuous compliance with the HCl emission limit, for sources

that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 15 of § 63.10011, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple EGUs provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each EGU.

(4) A copy of all calculations and supporting documentation of maximum Hg fuel input, using Equation 8 of § 63.10011, that were done to demonstrate continuous compliance with the Hg emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of Hg emission rates, using Equation 11 of § 63.10011, that were done to demonstrate compliance with the Hg emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum Hg fuel input or Hg emission rates. You can use the results from one fuel analysis for multiple EGUs provided they are all burning the same fuel type. However, you must calculate Hg fuel input, or Hg emission rates, for each EGU.

(5) If consistent with § 63.10032(b) and (c), you choose to stack test less frequently than annually, you must keep annual records that document that your emissions in the previous stack test(s) were less than 90 percent of the applicable emission limit, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

(e) If you elect to average emissions consistent with § 63.10009, you must additionally keep a copy of the emission averaging implementation plan required in § 63.10009(g), all calculations required under § 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.10022.

(f) Records of the occurrence and duration of each startup and/or shutdown.

(g) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.

(h) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

§ 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 off site for the remaining 3 years.

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?

Table 10 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 U.S. EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the U.S. EPA) 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 of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; however, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.9991(a) and (b) under § 63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, approval of minor and intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of "test method" in § 63.2), and approval of alternative analytical methods requested under § 63.10008(b)(2).

(3) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under §§ 63.9991(a)(2) and 63.10009(g)(2).

(4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

§ 63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Anthracite coal means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388–77, 90, 91, 95, 98a, or 99 (incorporated by reference, see 40 CFR 63.14(b)(39)).

Bag leak detection system means a group of instruments that are capable of monitoring PM loadings in the exhaust of a fabric filter (i.e., baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative PM loadings.

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004) $^{\varepsilon 1}$ (incorporated by reference, see 40 CFR 63.14(b)(39)).

Boiler operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for the fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388–991^{1} (incorporated by reference, see 40 CFR 63.14(b)(39)), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered "coal" for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal or coal refuse either exclusively, in any combination together, or in any combination with other fuels in any amount.

Coal refuse means any by-product 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 with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

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

Cogeneration unit means a stationary, fossil fuel-fired EGU meeting the definition of "fossil fuel-fired" or stationary, integrated gasification combined cycle:

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

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

(i) For a topping-cycle cogeneration unit,

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

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

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

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combined-cycle gas stationary combustion turbine means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

Common stack means the exhaust of emissions from two or more affected units through a single flue.

Deviation. (1) Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, work practice standard, or monitoring requirement; or

(ii) 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.

(2) A deviation is not always a violation.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396–02a (incorporated by reference, see § 63.14(b)(40)).

Dry flue gas desulfurization technology, or *dry FGD,* or spray dryer absorber (SDA), or *spray dryer,* or *dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO_2 and HCl in the exhaust stream forming a dry powder material. Sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

Dry sorbent injection (DSI) means an add-on air pollution control system in which sorbent (e.g., conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases (such as SO_2 and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired 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 considered an electric utility steam generating unit.

Electrostatic precipitator or *ESP* means an add-on air pollution control device that is located downstream of the steam generating unit used to capture PM 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.

Equivalent means the following only as this term is used in Table 6 to subpart UUUUU:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the Hg, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (Hg) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table

6 to subpart UUUUU for the same purpose.

Fabric filter, or *FF,* or *baghouse* means an add-on air pollution control device that is located downstream of the steam generating unit used to capture PM by filtering gas streams through filter media.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable State implementation plan; and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of combusting more than 73 MWe (250 million Btu/hr, MMBtu/hr) heat input (equivalent to 25 MWe output) of fossil fuels. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their permits and have the appropriate fuel handling facilities on-site (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Fluidized bed boiler, or *fluidized bed combustor,* or *circulating fluidized boiler,* or *CFB* means a boiler utilizing a fluidized bed combustion process.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles which are maintained in a mobile suspension by the forward flow of air and combustion products.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in an EGU and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit that burns a synthetic gas derived from coal or solid oil-derived fuel in a combined-cycle gas turbine. No coal or solid oil-derived fuel is directly burned in the unit during operation.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004) $^{\varepsilon 1}$ (incorporated by reference, see § 63.14(a)(39)).

Liquid fuel includes, but is not limited to, distillate oil and residual oil.

Minimum pressure drop means 90 percent of the test average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means 90 percent of the test average effluent pH measured at the outlet of the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable HCl emission limit.

Minimum scrubber flow rate means 90 percent of the test average flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means 90 percent of the test average sorbent (or activated carbon) injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Minimum voltage or *amperage* means 90 percent of the test average voltage or amperage to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by ASTM Method D1835–03a (incorporated by reference, see § 63.14(b)(41)).

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Non-cogeneration unit means a unit that has a combustion unit of more than 25 MWe and that supplies more than 25 MWe to any utility power distribution system for sale.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se).

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (e.g., petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

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.

Particulate matter or *PM* means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an alternative method.

Pulverized coal boiler means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396–02a (incorporated by reference, see § 63.14(b)(40)).

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

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

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 integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004)$^{\varepsilon 1}$ (incorporated by reference, see § 60.14(a)(39)).

Unit designed for coal > 8,300 Btu/lb subcategory includes any EGU designed to burn a coal having a calorific value (moist, mineral matter-free basis) of greater than or equal to 19,305 kilojoules per kilogram (kJ/kg) (8,300 British thermal units per pound (Btu/lb)) in an EGU with a height-to-depth ratio of less than 3.82.

Unit designed for coal < 8,300 Btu/lb includes any EGU designed to burn a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) in an EGU with a height-to-depth ratio of 3.82 or greater.

Unit designed to burn liquid oil fuel subcategory includes any EGU that burned any liquid oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years, either alone or in combination with gaseous fuels.

Unit designed to burn solid oil-derived fuel subcategory includes any EGU that burned a solid fuel derived from oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years, either alone or in combination with other fuels.

Voluntary Consensus Standards or *VCS* mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: The U.S. States, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g. Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Wet flue gas desulfurization technology, or *wet FGD,* or *wet scrubber* means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO_2 and HCl.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to CAA section 112(h).

Tables to Subpart UUUUU of Part 63

As stated in § 63.9991, you must comply with the following applicable emission limits:

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
1. Coal-fired unit designed for coal ≥ 8,300 Btu/lb.	a. Total particulate matter (PM)	0.050 lb per MWh	Collect a minimum of 4 dscm per run.
	OR Total non-Hg HAP metals	OR 0.000040 lb per MWh	Collect a minimum of 4 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.000080 lb/GWh	
	Arsenic (As)	0.00020 lb/GWh	
	Beryllium (Be)	0.000030 lb/GWh	
	Cadmium (Cd)	0.00040 lb/GWh	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	Chromium (Cr)	0.020 lb/GWh	
	Cobalt (Co)	0.00080 lb/GWh	
	Lead (Pb)	0.00090 lb/GWh	
	Manganese (Mn)	0.0040 lb/GWh	
	Nickel (Ni)	0.0040 lb/GWh	
	Selenium (Se)	0.030 lb/GWh	
	b. Hydrogen chloride (HCl)	0.30 lb per GWh	For Method 26A, collect a minimum of 4 dscm per run.
	OR		
	Sulfur dioxide (SO_2)[1]	0.40 lb per MWh	SO_2 CEMS.
	c. Mercury (Hg)	0.000010 lb per GWh	Hg CEMS or Sorbent trap monitoring system.
2. Coal-fired unit designed for coal < 8,300 Btu/lb.	a. Total particulate matter (PM)	0.050 lb per MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	0.000040 lb per MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.000080 lb/GWh	
	Arsenic (As)	0.00020 lb/GWh	
	Beryllium (Be)	0.000030 lb/GWh	
	Cadmium (Cd)	0.00040 lb/GWh	
	Chromium (Cr)	0.020 lb/GWh	
	Cobalt (Co)	0.00080 lb/GWh	
	Lead (Pb)	0.00090 lb/GWh	
	Manganese (Mn)	0.0040 lb/GWh	
	Nickel (Ni)	0.0040 lb/GWh	
	Selenium (Se)	0.030 lb/GWh	
	b. Hydrogen chloride (HCl)	0.30 lb per GWh	For Method 26A, collect a minimum of 4 dscm per run.
	OR	OR	
	Sulfur dioxide (SO_2)[2]	0.40 lb per MWh	SO_2 CEMS.
	c. Mercury (Hg)	0.040 lb per GWh	Hg CEMS or Sorbent trap monitoring system.
3. IGCC unit	a. Particulate matter (PM)	0.050 lb per MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	0.000040 lb per MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.000080 lb/GWh	
	Arsenic (As)	0.00020 lb/GWh	
	Beryllium (Be)	0.000030 lb/GWh	
	Cadmium (Cd)	0.00040 lb/GWh	
	Chromium (Cr)	0.020 lb/GWh	
	Cobalt (Co)	0.00080 lb/GWh	
	Lead (Pb)	0.00090 lb/GWh	
	Manganese (Mn)	0.0040 lb/GWh	
	Nickel (Ni)	0.0040 lb/GWh	
	Selenium (Se)	0.030 lb/GWh	
	b. Hydrogen chloride (HCl)	0.30 lb per GWh	For Method 26A, collect a minimum of 4 dscm per run.
	OR		
	Sulfur dioxide (SO_2)[3]	0.40 lb per MWh	SO_2 CEMS.
	c. Mercury (Hg)	0.000010 lb per GWh	Hg CEMS or Sorbent trap monitoring system.
4. Liquid oil-fired unit	a. Total HAP metals	0.00040 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.0020 lb/GWh	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs—Continued

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	Arsenic (As)	0.0020 lb/GWh	
	Beryllium (Be)	0.00070 lb/GWh	
	Cadmium (Cd)	0.00040 lb/GWh	
	Chromium (Cr)	0.020 lb/GWh	
	Cobalt (Co)	0.0060 lb/GWh	
	Lead (Pb)	0.0060 lb/GWh	
	Manganese (Mn)	0.030 lb/GWh	
	Nickel (Ni)	0.040 lb/GWh	
	Selenium (Se)	0.0040 lb/GWh	
	Mercury (Hg)	0.00010 lb/GWh	For Method 30B sample volume determination (8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	0.00050 lb/MWh	For Method 26A, collect a minimum of 4 dscm per run.
	c. Hydrogen fluoride (HF)	0.00050 lb/MWh	For Method 26A, collect a minimum of 4 dscm per run.
5. Solid oil-derived fuel-fired unit	a. Particulate matter (PM)	0.050 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	0.00020 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.00090 lb/GWh	
	Arsenic (As)	0.0020 lb/GWh	
	Beryllium (Be)	0.000080 lb/GWh	
	Cadmium (Cd)	0.0070 lb/GWh	
	Chromium (Cr)	0.0060 lb/GWh	
	Cobalt (Co)	0.0020 lb/GWh	
	Lead (Pb)	0.020 lb/GWh	
	Manganese (Mn)	0.0070 lb/GWh	
	Nickel (Ni)	0.0070 lb/GWh	
	Selenium (Se)	0.00090 lb/GWh	
	b. Hydrogen chloride (HCl)	0.00030 lb/MWh	For Method 26A, collect a minimum of 4 dscm per run.
	OR		
	Sulfur dioxide (SO_2) [4]	0.40 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	0.0020 lb/GWh	Hg CEMS or Sorbent trap monitoring system.

As stated in § 63.9991, you must comply with the following applicable emission limits: [5]

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
1. Coal-fired unit designed for coal ≥ 8,300 Btu/lb.	a. Total particulate matter (PM)	0.030 lb/MMBtu or 0.30 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	0.000040 lb/MMBtu 0.00040 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.60 lb/TBtu or 0.0060 lb/GWh.	
	Arsenic (As)	2.0 lb/TBtu or 0.020 lb/GWh.	
	Beryllium (Be)	0.20 lb/TBtu or 0.0020 lb/GWh.	
	Cadmium (Cd)	0.30 lb/TBtu or 0.0030 lb/GWh.	

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs—Continued

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	Chromium (Cr)	3.0 lb/TBtu or 0.030 lb/GWh.	
	Cobalt (Co)	0.80 lb/TBtu or 0.0080 lb/GWh.	
	Lead (Pb)	2.0 lb/TBtu or 0.020 lb/GWh.	
	Manganese (Mn)	5.0 lb/TBtu or 0.050 lb/GWh.	
	Nickel (Ni)	4.0 lb/TBtu or 0.040 lb/GWh.	
	Selenium (Se)	6.0 lb/TBtu or 0.060 lb/GWh.	
	b. Hydrogen chloride (HCl)	0.0020 lb per MMBtu or 0.020 lb per MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 60 liters per run.
	OR		
	Sulfur dioxide (SO_2)[6]	0.20 lb per MMBtu or 2.0 lb per MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.0 lb/TBtu or 0.008 lb/GWh	LEE Testing for 28–30 days with 10 days maximum per run or Hg CEMS or Sorbent trap monitoring system.
2. Coal-fired unit designed for coal < 8,300 Btu/lb	a. Total particulate matter (PM)	0.030 lb/MMBtu or 0.30 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	0.000040 lb/MMBtu 0.00040 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.60 lb/TBtu or 0.0060 lb/GWh.	
	Arsenic (As)	2.0 lb/TBtu or 0.020 lb/GWh.	
	Beryllium (Be)	0.20 lb/TBtu or 0.0020 lb/GWh.	
	Cadmium (Cd)	0.30 lb/TBtu or 0.0030 lb/GWh.	
	Chromium (Cr)	3.0 lb/TBtu or 0.030 lb/GWh.	
	Cobalt (Co)	0.80 lb/TBtu or 0.0080 lb/GWh.	
	Lead (Pb)	2.0 lb/TBtu or 0.020 lb/GWh.	
	Manganese (Mn)	5.0 lb/TBtu or 0.050 lb/GWh.	
	Nickel (Ni)	4.0 lb/TBtu or 0.040 lb/GWh.	
	Selenium (Se)	6.0 lb/TBtu or 0.060 lb/GWh.	
	b. Hydrogen chloride (HCl)	0.0020 lb per MMBtu or 0.020 lb per MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 60 liters per run.
	OR		
	Sulfur dioxide (SO_2)[7]	0.20 lb per MMBtu or 2.0 lb per MWh.	SO_2 CEMS.
	c. Mercury (Hg)	4.0 lb/TBtu or 0.040 lb/GWh	LEE Testing for 28–30 days with 10 days maximum per run or Hg CEMS or Sorbent trap monitoring system.
3. IGCC unit	a. Total particulate matter (PM)	0.050 lb/MMBtu or 0.30 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0 lb/TBtu or 0.050 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.40 lb/TBtu or 0.0040 lb/GWh.	
	Arsenic (As)	2.0 lb/TBtu or 0.020 lb/GWh.	
	Beryllium (Be)	0.030 lb/TBtu or 0.0030 lb/GWh.	
	Cadmium (Cd)	0.20 lb/TBtu or 0.0020 lb/GWh.	
	Chromium (Cr)	3.0 lb/TBtu or 0.020 lb/GWh.	
	Cobalt (Co)	2.0 lb/TBtu or 0.0040 lb/GWh.	
	Lead (Pb)	0.0002 lb/MMBtu or 0.003 lb/MWh.	
	Manganese (Mn)	3.0 lb/TBtu or 0.020 lb/GWh.	
	Nickel (Ni)	5.0 lb/TBtu or 0.050 lb/GWh.	
	Selenium (Se)	22.0 lb/TBtu or 0.20 lb/GWh.	
	b. Hydrogen chloride (HCl)	0.00050 lb/MMBtu or 0.0030 lb/MWh.	For Method 26A, collect a minimum of 4 dscm per run.

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	c. Mercury (Hg)	3.0 lb/TBtu or 0.020 lb/GWh	LEE Testing for 28–30 days with 10 days maximum per run or Hg CEMS or Sorbent trap monitoring system.
4. Liquid oil-fired unit	a. Total HAP metals	0.000030 lb/MMBtu or 0.00030 lb/MWh.	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.20 lb/TBtu or 0.0030 lb/GWh.	
	Arsenic (As)	0.60 lb/TBtu or 0.0070 lb/GWh.	
	Beryllium (Be)	0.060 lb/TBtu or 0.00070 lb/GWh.	
	Cadmium (Cd)	0.10 lb/TBtu or 0.0020 lb/GWh.	
	Chromium (Cr)	2.0 lb/TBtu or 0.020 lb/GWh.	
	Cobalt (Co)	3.0 lb/TBtu or 0.020 lb/GWh.	
	Lead (Pb)	2.0 lb/TBtu or 0.030 lb/GWh.	
	Manganese (Mn)	5.0 lb/TBtu or 0.060 lb/GWh.	
	Nickel (Ni)	8.0 lb/TBtu or 0.080 lb/GWh.	
	Selenium (Se)	2.0 lb/TBtu or 0.020 lb/GWh.	
	Mercury (Hg)	0.050 lb/TBtu or 0.00070 lb/GWh	For Method 29, collect a minimum of 4 dscm per run or for Method 30B sample volume determination (8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	0.00030 lb/MMBtu or 0.0030 lb/MWh.	For Method 26A, collect a minimum of 4 dscm per run.
	c. Hydrogen fluoride (HF)	0.00020 lb/MMBtu or 0.0020 lb/MWh.	For Method 26A, collect a minimum of 4 dscm per run.
5. Solid oil-derived fuel-fired unit	a. Total particulate matter (PM)	0.20 lb/MMBtu or 2.0 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	0.000050 lb/MMBtu or 0.0010 lb/MWh.	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.40 lb/TBtu or 0.0070 lb/GWh.	
	Arsenic (As)	0.40 lb/TBtu or 0.0040 lb/GWh.	
	Beryllium (Be)	0.070 lb/TBtu or 0.00070 lb/GWh.	
	Cadmium (Cd)	0.40 lb/TBtu or 0.0040 lb/GWh.	
	Chromium (Cr)	2.0 lb/TBtu or 0.020 lb/GWh.	
	Cobalt (Co)	2.0 lb/TBtu or 0.020 lb/GWh.	
	Lead (Pb)	11.0 lb/TBtu or 0.020 lb/GWh.	
	Manganese (Mn)	3.0 lb/TBtu or 0.040 lb/GWh.	
	Nickel (Ni)	9.0 lb/TBtu or 0.090 lb/GWh.	
	Selenium (Se)	2.0 lb/TBtu 0.020 lb/GWh.	
	b. Hydrogen chloride (HCl)	0.0050 lb/MMBtu or 0.080 lb/GWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 60 liters per run.
	OR		
	Sulfur dioxide (SO_2)[8]	0.40 lb/MMBtu or 5.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	0.20 lb/TBtu or 0.0020 lb/GWh	LEE Testing for 28–30 days with 10 days maximum per run or Hg CEMS or Sorbent trap monitoring system.

[5] footnote.

[6] footnote.

[7] footnote.

[8] The alternate sulfur dioxide limit may not be used if your EGU does not have some form of flue gas desulfurization system installed.

As stated in § 63.9991, you must comply with the following applicable work practice standards:

Table 3 to Subpart UUUUU of Part 63—Work Practice Standards

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a performance test of the EGU annually as specified in § 63.10005.
2. A new EGU	Conduct a performance test of the EGU annually as specified in § 63.10005.

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

If you demonstrate compliance using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control	a. Maintain the pressure drop at or above the lowest 1-hour average pressure drop across the wet scrubber and the liquid flow rate at or above the lowest 1-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the PM emissions limitation.
2. Wet acid gas scrubbers	a. Maintain the pH at or above the lowest 1-hour average pressure drop across the wet scrubber and the liquid flow-rate at or above the lowest 1-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emissions limitation.
3. Fabric filter control	a. Install and operate a bag leak detection system according to § 63.10010 and operate the fabric filter such that the bag leak detection system does not initiate alarm mode more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control.	a. This option is only for EGUs that operate additional wet control systems. Maintain the secondary power input of the electrostatic precipitator at or above the lowest 1-hour average secondary power measured during the most recent performance test demonstrating compliance with the PM emissions limitation.
5. Dry scrubber, DSI, or carbon injection control.	Maintain the sorbent or carbon injection rate at or above the lowest 1-hour average sorbent flow rate measured during the most recent performance test demonstrating compliance with the Hg emissions limitation.
6. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rate calculated according to § 63.10011(d)(3), (4) and/or (5) is less than the applicable emission limits.
7. Performance testing	For EGUs that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance test.
8. PM CEMS	Maintain the PM concentration (mg/dscm) at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the total PM emissions limitation.

As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources: [9]

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .[10]
1. Particulate matter (PM).	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, Appendix A–1 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, Appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at 40 CFR part 60, Appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.
		d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, Appendix A–3 of this chapter.
		e. Measure the PM emissions concentrations and determine the filterable and condensable fractions, as well as total PM.	Method 202 at 40 CFR part 51, Appendix M of this chapter for condensable PM emissions from units and Method 5 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, Appendix A–3 or A–6 of this chapter for filterable PM emissions. Note that the Method 5 front half temperature shall be 320 °F ± 25 °F.
		f. Convert emissions concentration to lb per MMBtu emissions rates or lb/MWh emissions rates.	Method 19 F-factor methodology at 40 CFR part 60, Appendix A–7 of this chapter, or calculate using mass emissions rate and electrical output data.
2. Total or individual non-Hg HAP metals.	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, Appendix A–1 of this chapter.

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[9] For emissions calculations involving periods of startup or shutdown, use procedures in § 63.10005(l).

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE STACK TESTING REQUIREMENTS—Continued

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .[10]
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, Appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at 40 CFR part 60, Appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.
		d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, Appendix A–3 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration.	Method 29 at 40 CFR part 60, Appendix A–8 of this chapter. Determine total filterable HAP metals according to section 8.3.1.1 prior to beginning metals analyses.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb per MMBtu or lb per MWh emissions rates.	Method 19 F-factor methodology at 40 CFR part 60, Appendix A–7 of this chapter, or calculate using mass emissions rate and electrical output data.
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF).	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, Appendix A–1 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, Appendix A–2 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at 40 CFR part 60, Appendix A–2 of this chapter, or ANSI/ASME PTC 19.10–1981.
		d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, Appendix A–3 of this chapter.
		e. Measure the HCl and HF emissions concentrations.	Method 26 if there are no entrained water droplets in the exhaust stream or 26A if there are entrained water droplets in the exhaust stream at 40 CFR part 60, Appendix A–8 of this chapter.
		f. Convert emissions concentration to lb per MMBtu or lb per MWh emissions rates.	Method 19 F-factor methodology at 40 CFR part 60, Appendix A–7 of this chapter, or calculate using mass emissions rate and electrical output data.
	OR	OR	
	HCl and/or HF CEMS	a. Install, operate, and maintain the CEMS	PS 15 or 6 at 40 CFR part 60, Appendix B of this chapter and QA Procedure 1 at 40 CFR part 60, Appendix F of this chapter.
		b. Install, operate, and maintain the diluents gas, flow rate, and/or moisture monitoring systems.	Section 4.1.3 and 5.3 of Appendix A of this subpart.
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates.	Method 19 F-factor methodology at 40 CFR part 60, Appendix A–7 of this chapter, or calculate using mass emissions rate and electrical output data.
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, Appendix A–1 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, Appendix A–1 or A–2 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at 40 CFR part 60, Appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.
		d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, Appendix A–3 of this chapter.
		e. Measure the Hg emission concentration	Method 29 or 30B at 40 CFR part 60, Appendix A–8 of this chapter or ASTM Method D6784–02 (2008) as specified.
		f. Convert emissions concentration to lb per TBtu emissions rates.	Section 6 of Appendix A of this subpart.
	OR	OR	
	Hg CEMS	a. Install, operate, and maintain the CEMS	Sections 3.2.1 and 5.1 of Appendix A of this subpart.
		b. Install, operate, and maintain the diluents gas, flow rate, and/or moisture monitoring systems.	Section 4.1.3 and 5.3 of Appendix A of this subpart.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE STACK TESTING REQUIREMENTS—Continued

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .[10]
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates.	Section 6 of Appendix A of this subpart.
	OR	OR	
	Sorbent trap monitoring system	a. Install, operate, and maintain the sorbent trap monitoring system.	Sections 3.2.2 and 5.2 of Appendix A of this subpart.
		b. Install, operate, and maintain the diluents gas, flow rate, and/or moisture monitoring systems.	Section 4.1.3 and 5.3 of Appendix A of this subpart.
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates.	Section 6 of Appendix A of this subpart.
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points.	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at 40 CFR part 60, Appendix A–1 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, Appendix A–1 or A–2 of this chapter or flow monitoring systems certified by Section 4.1.3 and 5.3 of Appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at 40 CFR part 60, Appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981 or diluent gas monitoring systems certified by Section 4.1.3 and 5.3 of Appendix A of this subpart.
		d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, Appendix A–3 of this chapter or moisture monitoring systems certified by Section 4.1.3 and 5.3 of Appendix A of this subpart.
		e. Measure the Hg emission concentration	Method 30B at 40 CFR part 60, Appendix A–8 of this chapter.
		f. Convert emissions concentrations to 30 boiler operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates.	Section 6 of Appendix A of this subpart.
		g. Convert 30 boiler operating day rolling average lb per MMBtu pr lb/MWh to lb per year.	Potential maximum annual heat input in MMBtu or potential maximum electricity generated in MWh.
5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, operate, and maintain the CEMS	PS 2 or 6 at 40 CFR part 60, Appendix B of this chapter and QA Procedure 1 at 40 CFR part 60, Appendix F of this chapter.
		b. Install, operate, and maintain the diluents gas, flow rate, and/or moisture monitoring systems.	Section 4.1.3 and 5.3 of Appendix A of this subpart.
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates.	Method 19 F-factor methodology at 40 CFR part 60, Appendix A–7 of this chapter, or calculate using mass emissions rate and electrical output data.

As stated in § 63.10008, you must comply with the following requirements for fuel analysis testing for existing, new, or reconstructed affected sources. However, equivalent methods may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

TABLE 6 TO SUBPART UUUUU OF PART 63—FUEL ANALYSIS REQUIREMENTS

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .[11]
1. Mercury (Hg)	a. Collect fuel samples	Procedure in § 63.10008(c) or ASTM D2234/D2234M (for coal) or equivalent.
	b. Composite fuel samples	Procedure in § 63.10008(d) or equivalent.

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[10] All ASTM, ANSI, and ASME methods are incorporated by reference.

[11] All ASTM, ANSI, and ASME methods are incorporated by reference.

TABLE 6 TO SUBPART UUUUU OF PART 63—FUEL ANALYSIS REQUIREMENTS—Continued

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . . [11]
	c. Prepare composited fuel samples	EPA SW–846–3020A (for liquid samples) or ASTM D2013/D2013M– (for coal) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 (for coal) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 or equivalent.
	f. Measure Hg concentration in fuel sample	ASTM D6722–01 (for coal) or SW–846–7471A (for solid samples) or SW–846–7470A (for liquid samples) or equivalent.
	g. Convert concentration into units of pounds of pollutant per TBtu of heat content or lb per MWh.	Method 19 F-factor methodology at 40 CFR part 60, Appendix A–7 of this chapter, or calculate using mass emissions rate and electrical output data.
2. Other non-Hg HAP metals	a. Collect fuel samples	Procedure in § 63.10008(c) or ASTM D2234/D2234M (for coal) or equivalent.
	b. Composite fuel samples	Procedure in § 63.10008(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3020A (for liquid samples) or ASTM D2013/D2013M– (for coal) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 (for coal) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 or equivalent.
	f. Measure other non-Hg HAP metals concentrations in fuel sample.	EPA SW–846–6010B or ASTM D3683 (for coal samples) or equivalent; EPA SW–846–6010B (for other solid fuel samples) or equivalent; or EPA SW–846–6020 (for liquid fuel samples) or equivalent.
	g. Convert concentration into units of pounds of pollutant per TBtu of heat content or lb per MWh.	Method 19 F-factor methodology at 40 CFR part 60, Appendix A–7 of this chapter, or calculate using mass emissions rate and electrical output data.
	b. Composite fuel samples	Procedure in § 63.10008(d) or equivalent.
3. Hydrogen chloride (HCl)	a. Collect fuel samples	Procedure in § 63.10008(c) or D2234/D2234M (for coal) or equivalent.
	b. Composite fuel samples	Procedure in § 63.10008(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3020A (for liquid samples), EPA SW–846–3050B (for solid samples), or ASTM D2013/D2013M (for coal) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 (for coal) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 or equivalent.
	f. Measure chlorine concentration in fuel sample.	EPA SW–846–9250 or ASTM D6721 (for coal) or equivalent, or EPA SW–846–9250 or ASTM E776 (for solid or liquid samples) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content or lb per MWh.	Method 19 F-factor methodology at 40 CFR part 60, Appendix A–7 of this chapter, or calculate using mass emissions rate and electrical output data.
4. Hydrogen fluoride (HF)	a. Collect fuel samples	Procedure in § 63.10008(c) or D2234/D2234M (for coal) or equivalent.
	b. Composite fuel samples	Procedure in § 63.10008(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3020A (for liquid samples), EPA SW–846–3050B (for solid samples), or ASTM D2013/D2013M (for coal) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 (for coal) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 or equivalent.
	f. Measure chlorine concentration in fuel sample.	EPA SW–846–9250 or ASTM D6721 (for coal) or equivalent, or EPA SW–846–9250 or ASTM E776 (for solid or liquid samples) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	Method 19 F-factor methodology at 40 CFR part 60, Appendix A–7 of this chapter.

As stated in § 63.10007, you must comply with the following requirements for establishing operating limits:

TABLE 7 TO SUBPART UUUUU OF PART 63—ESTABLISHING OPERATING LIMITS

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. Particulate matter (PM), mercury (Hg), or other non-Hg HAP metals.	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.10011(c).	(1) Data from the pressure drop and liquid flow rate monitors and the PM, Hg, or other non-Hg HAP metals performance test.	(a) You must collect pressure drop and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average hourly pressure drops and liquid flow rates for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).	i. Establish a site-specific secondary power input according to § 63.10011(c).	(1) Data from the secondary power input during the PM, Hg, or other non-Hg HAP metals performance test.	(a) You must collect secondary voltage and current and calculate total ESP secondary power input data every 15 minutes during the entire period of the performance tests; (b) Determine the average hourly total secondary power inputs for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	c. Filterable PM results obtained from performance testing and are measured continuously using PM CEMS.	i. Establish a site-specific filterable PM concentration according to § 63.10011(d).	(1) Data from the PM performance test.	(a) You must collect at least 3 test runs of Method 5 filterable PM results.
2. Hydrogen chloride (HCl) or hydrogen fluoride (HF).	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pH and flow rate operating limits according to § 63.10011(c).	(1) Data from the pH and liquid flow rate monitors and the HCl performance test.	(a) You must collect pH and liquid flow rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average hourly pH liquid flow rates for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	b. Dry scrubber or DSI operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.10011(c). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.	(1) Data from the sorbent injection rate monitors and HCl or Hg performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average hourly sorbent injection rates of the three test run averages measured during the performance test.

As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

TABLE 8 TO SUBPART UUUUU OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Fabric filter bag leak detection operation	Installing and operating a bag leak detection system according to § 63.10010 and operating the fabric filter such that the requirements in § 63.10021(a)(9) are met.
2. Wet PM scrubber pressure drop and liquid flow-rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.10010 and 63.10020; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.10011(c).
3. Wet acid gas scrubber pH and liquid flow rate.	a. Collecting the pH and liquid flow rate monitoring system data according to §§ 63.10010 and 63.10020; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average pH and liquid flow-rate at or above the operating limits established during the performance test according to § 63.10011(c).
4. Dry scrubber or DSI sorbent or carbon injection rate.	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber or DSI according to §§ 63.10010 and 63.10020; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average sorbent or carbon injection rate at or above the operating limit established during the performance test according to § 63.10011(c).
5. Electrostatic precipitator secondary power input.	a. Collecting the secondary power input monitoring system data for the electrostatic precipitator according to §§ 63.10010 and 63.10020; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average secondary power input at or above the operating limits established during the performance test according to § 63.10011(c).
6. Fuel pollutant content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.10011(c) or (d) as applicable; and b. Keeping monthly records of fuel use according to § 63.10021(a).
7. Filterable PM as measured by PM CEMS	a. Collecting the PM concentration data using a PM CEMS installed, operated and maintained in accordance with PS 11 at 40 CFR part 60, Appendix B of this chapter and QA Procedure 5 at 40 CFR part 60, Appendix F of this chapter; b. Converting hourly emissions concentrations to 30 boiler operating mg/dscm values; and c. Maintaining the 30 boiler operating day rolling average mg/dscm values below the operating limits established during the performance test according to § 63.10011(d).

As stated in § 63.10031, you must comply with the following requirements for reports:

TABLE 9 TO SUBPART UUUUU OF PART 63—REPORTING REQUIREMENTS

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.10031(c)(1) through (11) through (11); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e); and d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in § 63.10(d)(5)(i).	Semiannually according to the requirements in § 63.10031(b).

TABLE 9 TO SUBPART UUUUU OF PART 63—REPORTING REQUIREMENTS—Continued

You must submit a(n)	The report must contain . . .	You must submit the report . . .
2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the emission standard.	a. Actions taken for the event; and	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and
	b. The information in § 63.10(d)(5)(ii)	ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:

TABLE 10 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c), (f)(2)–(3), (g), (h)(2)–(h)(9), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.7(a), (b), (c), (d), (e)(2)–(e)(9), (f), (g), and (h).	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	
63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1), (c), (d)(1)–(2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii)–(ix)	Other CMS requirements	Yes.
§ 63.10(b)(3), and (d)(3)–(5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.

TABLE 10 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Applies to subpart UUUUU
§ 63.10(c)(11)	Recording corrective actions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See 63.10031(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13–63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§ 63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3)–(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)–(4), (c)(9).	Reserved	No.

Appendix A to Subpart UUUUU—Hg Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (e.g., lb/TBtu or lb/GWh), regardless of speciation. The monitoring, recordkeeping, and reporting provisions of this appendix shall be considered to be met to the extent that they have already been, and are continuing to be, met or exceeded under another Federal or State program.

1.2 *Initial Certification and Recertification Procedures.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

1.3 *Quality Assurance and Quality Control Requirements.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.

1.4 *Missing Data Procedures.* The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which the CEMS fails to produce quality-assured Hg mass emissions data is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions for Various Configurations

2.1 *Single Unit-Single Stack Configuration.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, the owner or operator shall install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system and any other necessary monitoring components needed to express the measured Hg emissions in the units of the applicable emissions standard, in accordance with section 3.2 of this appendix.

2.2 *Unit Utilizing Common Stack with Other Affected Unit(s).* When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, the owner or operator shall either:

2.2.1 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section in the duct to the common stack from each unit; or

2.2.2 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section in the common stack.

2.3 *Unit Utilizing Common Stack with Non-affected Units.* When one or more affected units shares a common stack with one or more non-affected units, the owner or operator shall either:

2.3.1 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section in the duct to the common stack from each affected unit; or

2.3.2 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section in the common stack and attribute all of the Hg emissions measured at the common stack to the affected unit(s).

2.4 *Unit with a Main Stack and a Bypass Stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, the owner and operator shall either:

2.4.1 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section on both the main stack and the bypass stack; or

2.4.2 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section only on the main stack, and report the maximum potential Hg concentration (as defined in section 3.2.1.4.1 of this appendix) for each unit operating hour in which the bypass stack is used.

2.5 *Unit with Multiple Stack or Duct Configuration.* If the flue gases from an affected unit either: are discharged to the atmosphere through more than one stack; or are fed into a single stack through two or more ducts and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:

2.5.1 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section in each of the multiple stacks; or

2.5.2 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section in each of the ducts that feed into the stack.

3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (i.e., sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg (Hg^0, CAS Number 7439–97–6) and oxidized forms of Hg.

3.1 *Definitions.*

3.1.1 *Mercury Continuous Emission Monitoring System or Hg CEMS* means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: Sample acquisition, Hg^{+2} to Hg^0 converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS).

3.1.2 *Sorbent Trap Monitoring System* means the equipment required to monitor Hg emissions continuously, using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a rate proportional to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter (μg/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 *NIST-traceable elemental Hg standards* means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards"; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators", or an interim version of that protocol.

3.1.5 *NIST-traceable source of oxidized Hg* means a generator that is capable of providing known concentrations of vapor phase mercuric chloride ($HgCl_2$), and that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators", or an interim version of that protocol.

3.1.6 Calibration Gas means a NIST-traceable gas standard containing known concentration of a gaseous species that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span value* means a conservatively high estimate of the gas concentrations or stack gas flow rates to be measured by a CEMS. For a Hg pollutant concentration monitor, the span value should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate.

3.1.8 *Zero-Level Gas* means calibration gas with a concentration that is below the level detectable by a gas monitoring system.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed either to assess the ability of a gas monitor to measure the concentrations of calibration gases accurately, or the ability of a flow monitor to read electronic reference signals accurately. A zero-level gas (or signal) and an upscale gas (or signal) are required for this test. For gas monitors, either a mid-level gas or a high-level gas may be used. For a flow monitor, an upscale signal of 50 to 70 percent of the calibration span value is required. For a Hg CEMS, the upscale gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a gas analyzer is linear across its measurement range. Three calibration gas standards (i.e., low, mid, and high-level gases) are required for this test. For a Hg CEMS, elemental Hg calibration standards are required.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a gas monitor, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. For a Hg CEMS, the high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit or RATA* means a series of nine or more test runs, directly comparing readings from a CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Unit Operating Day* means a calendar day in which a unit combusts any fuel.

3.1.20 *QA Operating Quarter* means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A–1. The CEMS in Figure A–1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

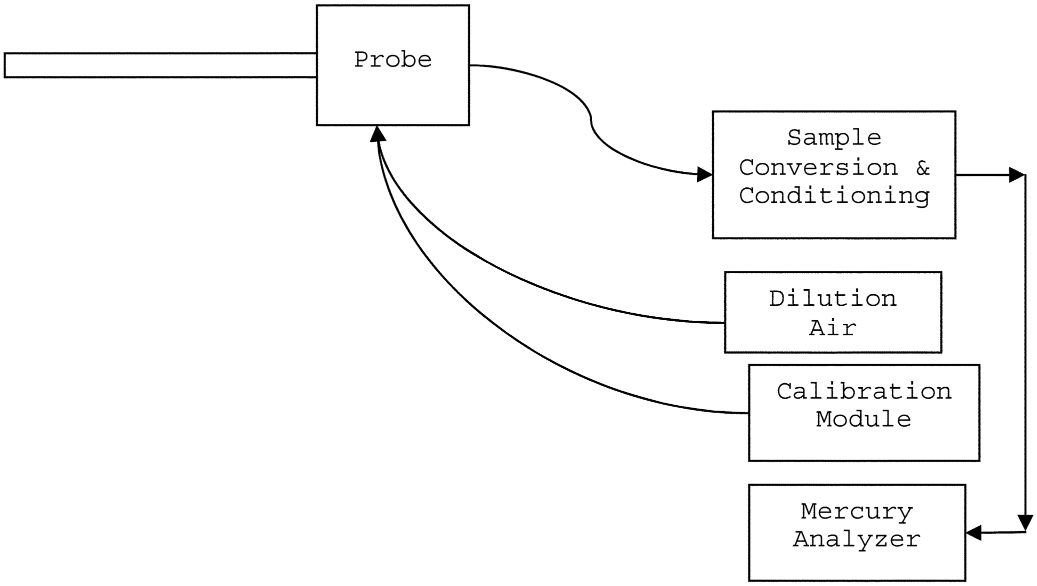

FIGURE A-1. TYPICAL MERCURY CEMS

3.2.1.1 *Equipment Specifications.*

3.2.1.1.1 *Materials of Construction.* All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon™, quartz, treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 *Temperature Considerations.* All system components prior to the Hg^{+2} to Hg^0 converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 *Measurement System Components.*

3.2.1.1.3.1 Sample Probe. The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 *Filter or Other Particulate Removal Device.* The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 *Sample Line.* The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 *Conditioning Equipment.* For wet basis systems, such as the one shown in Figure A–1, the sample must be kept above its dew point either by: Heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 *Sampling Pump.* A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A–1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump may be constructed of any material that is non-reactive to the gas being sampled.

3.2.1.1.3.6 *Calibration Gas System(s).* Design and equip each Hg monitor to permit the introduction of known concentrations of elemental Hg and $HgCl_2$ separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.1.3.7 *Sample Gas Delivery.* The sample line may feed directly to a converter, to a by-pass valve (for Hg speciating systems), or to a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.1.3.8 *Hg Analyzer.* An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.1.3.9 *Data Recorder.* A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 *Reagents and Standards.*

3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this section) shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg^0 and $HgCl_2$ are required. Special reagents and equipment may be needed to prepare the Hg^0 and $HgCl_2$ gas standards (e.g., NIST-traceable solutions of $HgCl_2$ and gas generators equipped with mass flow controllers).

3.2.1.2.2 *Required Calibration Gas Concentrations.*

3.2.1.2.2.1 *Zero-Level Gas.* A zero-level calibration gas with a Hg concentration below the detectable limit of the analyzer is required for calibration error tests and cycle time tests of the CEMS.

3.2.1.2.2.2 *Low-Level Gas.* A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks and oxidized Hg standards are required for the system integrity checks.

3.2.1.2.2.3 *Mid-Level Gas.* A mid-level calibration gas with a Hg concentration of 50 to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

3.2.1.2.2.4 *High-Level Gas.* A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error and cycle time tests.

3.2.1.3 *Installation and Measurement Location.* For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (i.e., a flow monitor, CO_2 or O_2 monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: That represents the emissions exiting to the atmosphere; and at which it is likely that the CEMS can pass the relative accuracy test.

3.2.1.4 *Monitor Span and Range Requirements.* Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

3.2.1.4.1 *Maximum Potential Concentration.* There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 μg/scm for all coal ranks (including coal refuse) except for lignite; for lignite, use 16 μg/scm. Option 2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (i.e., the weight percentage) from at least three representative fuel samples, together with other available information, including, but not limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

3.2.1.4.2 *Span Value.* To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 μg/scm, use the result as the span value. Otherwise, round off the result to the next highest integer. Alternatively, you may round off the span value to the next highest multiple of 10 μg/scm.

3.2.1.4.3 *Full-Scale Range.* The full-scale range of the Hg analyzer output must include the MPC.

3.2.2 *Sorbent Trap Monitoring System.* A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in accordance with Performance Specification 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

3.2.3 *Other Necessary Monitoring Systems.* When the applicable Hg emission limit is specified in units of lb/TBtu or lb/GWh, some or all of the monitoring systems described in paragraphs 3.2.3.1 and 3.2.3.2 of this section will be needed to convert the measured Hg concentrations to the units of the emissions standard. These additional monitoring systems shall be installed, certified, maintained, operated, and quality-assured according to the applicable provisions of this appendix (see section 4.1.3 of this appendix). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

3.2.3.1 *Heat Input-Based Emission Limits.* For a heat input-based Hg emission limit (e.g., in lb/TBtu), data from a certified CO_2 or O_2 monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be accounted for, as follows:

3.2.3.1.1 Determine the stack gas moisture content using a certified continuous moisture monitoring system; or

3.2.3.1.2 Use the moisture value determined during the most recent Hg emissions test while combusting the fuel type currently in use; or

3.2.3.1.3 For coal combustion, use a fuel-specific moisture default value. For anthracite coal, use 3.0% H_2O; for bituminous coal, use 6.0% H_2O; for sub-bituminous coal, use 8.0% H_2O; and for lignite, use 11.0% H_2O.

3.2.3.2 *Electrical Output-Based Emission Rates.* If the applicable Hg limit is electrical output-based (e.g., lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified flow rate monitor and (if applicable) moisture data.

3.2.3.3 *Span and Range of Flow Rate, Diluent Gas, and Moisture Monitors.* Set the span value of a CO_2 or O_2 monitor at 1.00 to 1.25 times the maximum potential concentration. Set the span value of a flow rate monitor at 1.00 to 1.25 times the maximum potential flow rate, in units of standard cubic feet per hour (scfh). If the units of measure for daily calibrations of the flow monitor are not expressed in scfh, convert the calculated span value from scfh to an equivalent "calibration span value" in the units of measure actually used for daily calibrations. Set the full-scale range of the CO_2, O_2, and flow monitors such that the majority of the data will fall between 20 and 80% of full-scale. For a continuous moisture sensor, there is no span value requirement; set up and operate the instrument according to the manufacturer's instructions.

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* All Hg CEMS and sorbent trap systems and the monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified prior to the applicable compliance date specified in § 63.9984.

4.1.1 *Hg CEMS.* Table A–1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests.

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in sections 3.1.8, 3.1.10, and 3.1.11 of this appendix). Either elemental or oxidized NIST-traceable Hg standards (as defined in sections 3.1.4 and 3.1.5 of this appendix) may be used for the test. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate each monitor in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over nonconsecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (i.e., resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A–1. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A–1.

TABLE A–1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR HG CEMS

For this required certification test . . .	The main performance specification[1] is . . .	The alternate performance specification[1] is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test[2]	$\lvert R - A \rvert \leq 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days.	$\lvert R - A \rvert \leq 1.0$ µg/scm	The alternate specification may be used on any day of the test.
Linearity check[3]	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas concentration at each calibration gas level.	$\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
3-level system integrity check[4]	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas concentration at each calibration gas level.	$\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
RATA	20.0% RA	$\lvert RM_{avg} - C_{avg} \rvert \leq 1.0$ µg/scm **	$RM_{avg} < 5.0$ µg/scm.
Cycle time test[2]	15 minutes.[5]		

[1] Note that $\lvert R - A \rvert$ is the absolute value of the difference between the reference gas value and the analyzer reading. $\lvert R - A_{avg} \rvert$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

[2] Use either elemental or oxidized Hg standards.

[3] Use elemental Hg standards.

[4] Use oxidized Hg standards. Not required if the CEMS does not have a converter.

[5] Stability criteria − Readings change by < 2.0% of span *or* by ≤0.5 µg/m^3, for 2 minutes.

** Note that $\lvert RM_{avg} - C_{avg} \rvert$ is the absolute difference between the mean reference method value and the mean CEMS value from the RATA. The arithmetic difference between RM_{avg} and C_{avg} can be either + or −.

4.1.1.2 *Linearity Check.* Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate each monitor at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A–1. The LE must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A–1. The SIE must either meet the main performance specification or the alternative specification in Table A–2. (**Note:** This test is not required if the CEMS does not have a converter).

4.1.1.4 *Cycle Time Test.* Perform the cycle time test, using a zero-level gas and a high-level calibration gas. Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 µg/scm (whichever is less restrictive) for two minutes.

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784–02 (the Ontario Hydro Method) and Methods 29, 30A, and 30B in appendix A–8 to part 60 of this chapter. When Method 29 or the Ontario Hydro Method is used, paired sampling trains are required. To validate a Method 29 or Ontario Hydro test run, calculate the relative deviation (RD) using Equation A–1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the average concentration is ≤1.0 µg/dscm, the RD must not exceed 20 percent. The RD results are also acceptable if the absolute difference between the two Hg concentrations does not exceed 0.03 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{\lvert C_a - C_b \rvert}{C_a + C_b} \, x\, 100 \qquad \text{(Eq. A-1)}$$

Where:

RD = Relative deviation between the Hg concentrations of samples “a” and “b” (percent)

C_a = Hg concentration of Hg sample “a” (µg/dscm)

C_b = Hg concentration of Hg sample “b” (µg/dscm)

4.1.1.5.1 *Special Considerations. Special Considerations.* A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. If 12 or more runs are performed, you may discard the results from a maximum of three runs for calculating relative accuracy. The minimum time per run is 21 minutes if Method 30A is used. If the Ontario Hydro Method, Method 29, or Method 30B is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when the Ontario Hydro Method or Method 29 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification 2 or 6 in Appendix B to part 60 of this chapter. The CEMS must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.5.3 *Bias Adjustment.* Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 *Sorbent Trap Monitoring Systems.* For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 *Reference Methods.* The acceptable reference methods for the RATA of a sorbent trap system are listed in paragraph 4.1.1.5 of this section.

4.1.2.2 *Special Considerations.* The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification 12B in Appendix B to part 60 of this chapter. The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.3 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the Hg concentration monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification 2 or 6 in appendix B to part 60 of this chapter. The main and alternative RATA performance specifications in Table A–1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.4 *Bias Adjustment.* Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 *Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems.* Monitoring systems that are used to measure stack gas volumetric flow rate and/or diluent gas concentration and/or stack gas moisture content in order to convert Hg concentration data to units of the applicable emission limit must be certified. The minimum certification test requirements and performance specifications for these systems are shown in Table A–2, below.

4.2 *Recertification.* Whenever the owner or operator makes a replacement, modification, or change to a certified Hg CEMS, sorbent trap monitoring system, flow rate monitoring system, diluent gas monitoring system, or moisture monitoring system that may significantly affect the ability of the system to accurately measure or record the Hg concentration, stack gas volumetric flow rate, CO_2 concentration, O_2 concentration, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the flow or concentration profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

TABLE A–2—MINIMUM REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR OTHER MONITORING SYSTEMS

For this required certification test . . .	Of this auxiliary monitoring system . . .	The main performance specification [1] is . . .	The alternate performance specification [2] is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test	O_2 or CO_2	$\lvert R - A \rvert \leq 0.5\%$ O_2 or CO_2 for both the zero and upscale gases, on each day of the test.		
7-day calibration error test	Flow rate	$\lvert R - A \rvert \leq 3.0\%$ of calibration span value for both the zero and upscale signals, on each day of the test.	$\lvert R - A \rvert \leq 0.01$ in. H_2O, for DP-type monitors.	The alternate specification may be used on any day of the tests.
Linearity check	O_2 or CO_2	$\lvert R - A_{avg} \rvert \leq 5.0\%$ of the reference gas value.	$\lvert R - A \rvert \leq 0.5\%$ O_2 or CO_2	The alternate specification may be used at any gas level.
Cycle time test	O_2 or CO_2	≤ 15 minutes.		
RATA	O_2 or CO_2	10.0% RA	$\lvert RM_{avg} - C_{avg} \rvert \leq 1.0\%$ O_2 or % CO_2.	
RATA	Flow rate	10.0% RA.		
RATA	Moisture	10.0% RA	$\lvert RM_{avg} - C_{avg} \rvert \leq 1.5\%$ H_2O.	

[1] Note that $\lvert R - A \rvert$ is the absolute value of the difference between the reference gas value and the analyzer reading. $\lvert R - A_{avg} \rvert$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

[2] Note that $\lvert RM_{avg} - C_{avg} \rvert$ is the absolute difference between the mean reference method value and the mean CEMS value from the RATA. The arithmetic difference between RM_{avg} and C_{avg} can be either + or −.

5. Ongoing Quality Assurance (QA) and Data Validation

5.1 *Hg CEMS.*

5.1.1 *Required QA Tests.* Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A–3, below.

5.1.2 *Test Frequency.* The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Perform calibration error tests of the Hg CEMS daily. Use either NIST-traceable elemental Hg standards or NIST-traceable oxidized Hg standards for these calibrations. A zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for “non-QA operating quarters”. A maximum of three consecutive exemptions for this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

TABLE A–3—ON–GOING QA TEST REQUIREMENTS FOR HG CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test	Daily	• Use either a mid- or high- level gas. • Use either elemental or oxidized Hg. • Calibrations are not required when the unit is not in operation.	$\lvert R - A \rvert \leq 5.0\%$ of span value; *or* $\lvert R - A \rvert \leq 1.0$ µg/scm.
Single-level system integrity check	Weekly[1]	• Required only for systems with converters. • Use oxidized Hg —either mid- or high-level. • Not required if daily calibrations are done with a NIST-traceable source of oxidized Hg.	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas value; *or* $\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm.
Linearity check *or* 3-level system integrity check.	Quarterly[3]	• Required in each "QA operating quarter"[2]—and no less than once every 4 calendar quarters. • 168 operating hour grace period available. • Use elemental Hg for linearity check. • Use oxidized Hg for system integrity check. • For system integrity check, CEMS must have a converter.	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas value, at each calibration gas level; *or* $\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm.
RATA	Annual[4]	• Test deadline may be extended for "non-QA operating quarters," up to a maximum of 8 quarters from the quarter of the previous test. • 720 operating hour grace period available.	20.0% RA; *or* $\lvert RM_{avg} - C_{avg} \rvert \leq 1.0$ µg/scm; *if* $RM_{avg} < 5.0$ µg/scm.

[1] "Weekly" means once every 168 unit operating hours.

[2] A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.

[3] "Quarterly" means once every QA operating quarter.

[4] "Annual" means once every four QA operating quarters.

5.1.2.3 A weekly single-level system integrity check (if required—see third column in Table A–3).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, i.e., once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions—the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stac operating hour grace period following that quarter.

5.1.3 *Data Validation.* The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any of the acceptance criteria for the required QA tests in Table A–3 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed.

5.1.4 *Grace Periods.*

5.1.4.1 A 168 unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.4.2 A 720 unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.4.3 There is no grace period for weekly system integrity checks. The test must be completed once every 168 unit or stack operating hours.

5.1.5 *Adjustment of Span.* If the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter, make any necessary adjustments to the MPC and span value. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 *Sorbent Trap Monitoring Systems.*

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification 12B (PS 12B) in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B–1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, i.e., once every four QA operating quarters.

5.2.2.2 The same RATA performance criteria specified in Table A–3 for Hg CEMS shall apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.2.4 Data validation for RATAs of the system shall be done in accordance with paragraph 5.1.3 of this section.

5.3 *Flow Rate, Diluent Gas, and Moisture Monitoring Systems.* The minimum on-going QA test requirements for these monitoring systems are summarized in Table A–4, below. The data validation provisions in paragraph 5.1.3 apply to these systems. The linearity grace period described in paragraph 5.1.4.1 applies to the O_2 and CO_2 monitors. The RATA grace period in paragraph 5.1.4.2 of this section applies to the O_2, CO_2, moisture, and flow rate monitors.

5.4 *QA/QC Program for Continuous Monitoring Systems.* The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for all continuous monitoring systems that are used to provide data under this subpart (i.e., all Hg CEMS, sorbent trap monitoring systems, and any associated monitoring systems used to convert Hg concentration data to the appropriate units of measure). At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors.

TABLE A–4—MINIMUM ON-GOING QUALITY ASSURANCE TEST REQUIREMENTS FOR AUXILIARY MONITORING SYSTEMS

Perform this QA test . . .	For this monitoring system . . .	At this frequency . . .	With these conditions and exceptions . . .	The acceptance criteria are . . .
Calibration error test	O_2 or CO_2	Daily	• Use either a mid or high level gas. • Not required on non-operating days.	$\lvert R - A \rvert \leq 1.0\%$ O_2 or CO_2.
Calibration error test	Flow rate	Daily	• Not required on non-operating days.	$\lvert R - A \rvert \leq 6.0\%$ of calibration span value or $\lvert R - A \rvert \leq 0.02$ in. H_2O for a DP-type monitor.
Interference check	Flow rate	Daily	• Not required on non-operating days.	Must be passed.
Linearity check	O_2 or CO_2	Quarterly	• Required in each QA operating quarter—but no less than once every 4 calendar quarters. • 168 operating hour grace period available.	$\lvert R - A \rvert \leq 5.0\%$ of reference gas *or* $\lvert R - A \rvert \leq 1.0\%$ O_2 or CO_2.
Leak check	Flow rate	Quarterly	• Required only for DP-type flow monitors.	Must be passed.
RATA	O_2 or CO_2	Annual ***	• Once every four QA operating quarters, not to exceed 8 calendar quarters.	$RA \leq 7.5\%$; *or* $\lvert RM_{avg} - C_{avg} \rvert \leq 0.7\%$ O_2 or CO_2.
RATA	Flow rate	Annual ***	• Once every four QA operating quarters, not to exceed 8 calendar quarters.	$RA \leq 7.5\%$.
RATA	Moisture	Annual ***	• Once every four QA operating quarters, not to exceed 8 calendar quarters.	$RA \leq 7.5\%$; *or* $\lvert RM_{avg} - C_{avg} \rvert \leq 1.0\%$ H_2O.

*** Note that these RATAs can still be passed at RA percentages up to and including 10.0% RA. Alternate specifications of $|R - A| \leq 1.0\%$ O_2 or CO_2 and $|R - A| \leq 1.5\%$ H_2O are also acceptable. However, for all of these acceptance criteria, the test frequency becomes *semiannual* (i.e., once every two QA operating quarters) monitors. The RATA grace period in paragraph 5.1.4.2 of this section applies to the O_2, CO_2, and flow rate monitors.

5.4.1 *General Requirements.*

5.4.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the monitoring system in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.4.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded (e.g., changing of flow monitor polynomial coefficients or K factors, changing the dilution ratio of a gas monitor, etc.), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 *Specific Requirements for Hg CEMS, Flow Rate, Diluent Gas, and Moisture Monitoring Systems.*

5.4.2.1 *Daily Calibrations, Linearity Checks and System Integrity Checks.* Keep a written record of the procedures used for daily calibrations of the Hg CEMS and all associated monitoring systems. If moisture and/or chlorine is added to the Hg calibration gas, explain how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for. Also keep records of the procedures used to perform linearity checks (of the Hg CEMS and, if applicable, the CO_2 or O_2 monitor) and the procedures for system integrity checks of the Hg CEMS. Explain how the test results are calculated and evaluated.

5.4.2.2 *Monitoring System Adjustments.* Explain how each component of the continuous emission monitoring system will be adjusted to provide correct responses to calibration gases or reference signals after routine maintenance, repairs, or corrective actions.

5.4.2.3 *Relative Accuracy Test Audits.* Keep a written record of procedures used for RATAs of the monitoring systems. Indicate the reference methods used and explain how the test results are calculated and evaluated.

5.4.3 *Specific Requirements for Sorbent Trap Monitoring Systems.*

5.4.3.1 *Sorbent Trap Identification and Tracking.* Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for tracking purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 *Monitoring System Integrity and Data Quality.* Explain the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also explain the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B–1 in section 9.0 of Performance Specification 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (e.g., wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 *Hg Analysis.* Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification 12B in Appendix B to part 60 of this chapter.

5.4.3.4 *Data Collection Period.* State, and provide the rationale for, the minimum acceptable data collection period (e.g., one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Include in the discussion such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 *Relative Accuracy Test Audit Procedures.* Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. Data Reduction and Calculations

6.1 *Data Reduction.*

6.1.1 Reduce the data from Hg CEMS and (as applicable) flow rate, diluent gas, and moisture monitoring systems to hourly averages, in accordance with § 60.13(h)(2) of this chapter.

6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (i.e., flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour.

6.1.4 Operating hours in which valid data are not obtained, either for Hg concentration or for another parameter, are considered to be hours of monitor downtime.

6.2 *Calculation of Hg Emission Rates.* Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 *Heat Input-Based Hg Emission Rates.* Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19–1 through 19–9 in EPA Method 19 in appendix A–7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by 6.24×10^{-11} to convert it from µg/scm to lb/scf.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by 10^6 to convert it to lb/TBtu.

6.2.1.4 If the heat input-based Hg emission rate limit must be met over a specified averaging period (e.g., a 30 boiler operating day rolling average), use Equation 19–19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. Do not include non-operating hours with zero emissions in the average.

6.2.2 *Electrical Output-Based Hg Emission Rates.* Calculate electrical output-based Hg emission limits in units of lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 First, calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A–2 of this section (for wet-basis measurements of Hg concentration) or Equation A–3 of this section (for dry-basis measurements), as applicable:

$$M_h = K\,C_h\,Q_h\,t_h \qquad \text{(Equation A-2)}$$

Where:

M_h = Hg mass emissions for the hour (lb)

K = Units conversion constant, 6.236×10^{-11} lb-scm/µg-scf

C_h = Hourly average Hg concentration, wet basis (µg/scm)

Q_h = Stack gas volumetric flow rate for the hour (scfh). (**Note:** Use unadjusted flow rate values; bias adjustment is not required)

t_h = Unit or stack operating time, fraction of the clock hour, expressed as a decimal. For example, t_h = 1.00 for a full operating hour, 0.50 for 30 minutes of operation, 0.00 for a non-operating hour, etc.) *or*

$$M_h = K\,C_h\,Q_h\,t_h\left(1 - B_{ws}\right) \qquad \text{(Equation A-3)}$$

Where:

M_h = Hg mass emissions for the hour (lb)

K = Units conversion constant, 6.236×10^{-11} lb-scm/µg-scf

C_h = Hourly average Hg concentration, dry basis (µg/dscm)

Q_h = Stack gas volumetric flow rate for the hour (scfh). (*Note:* Use unadjusted flow rate values; bias adjustment is not required)

t_h = Unit or stack operating time, fraction of the clock hour, expressed as a decimal. For example, t_h = 1.00 for a full operating hour, 0.50 for 30 minutes of operation, 0.00 for a non-operating hour, etc.)

B_{ws} = Moisture fraction of the stack gas, expressed as a decimal (equal to %H_2O/100)

6.2.2.2 Next, use Equation A–4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

$$E_{ho} = \frac{M_h}{(MW)_h (t_h)}\, x\, 10^3 \qquad \text{(Equation A-4)}$$

Where:

E_{ho} = Electrical output-based Hg emission rate (lb/GWh)

M_h = Hg mass emissions for the hour, from Equation A–2 or A–3 of this section, as applicable (lb)

$(MW)_h$ = Electrical load for the hour, in megawatts (MW)

t_h = Unit or stack operating time, fraction of the hour, expressed as a decimal. For example, t_h = 1.00 for a full operating hour, 0.50 for 30 minutes of operation, etc.)

10^3 = Conversion factor from megawatts to gigawatts

6.2.2.3 If the electrical output-based Hg emission rate limit must be met over a specified averaging period (e.g., a 30 boiler operating day rolling average), use Equation A–5 of this section to calculate the Hg emission rate for each averaging period.

$$\bar{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \qquad \text{(Equation A-5)}$$

Where:

$\bar{E}_o$ = Hg emission rate for the averaging period (lb/GWh)

E_{ho} = Electrical output-based hourly Hg emission rate for unit or stack operating hour "h" in the averaging period, from Equation A–4 of this section (lb/GWh)

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters. (*Note:* Do *not* include non-operating hours with zero emission rates in the average).

7. Recordkeeping and Reporting

7.1 *Recordkeeping Provisions.* The owner or operator shall, for each affected unit and each non-affected unit under section 2.3 of this appendix, maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record. The file shall contain the information in paragraphs 7.1.1 through 7.1.10 of this section.

7.1.1 *Monitoring Plan Records.* The owner or operator of an affected unit shall prepare and maintain a monitoring plan for each affected unit or group of units monitored at a common stack and each non-affected unit under section 2.3 of this appendix. The monitoring plan shall contain sufficient information on the continuous monitoring systems that provide data under this subpart, and how the data derived from these systems are sufficient to demonstrate that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.,* a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

7.1.1.2 *Contents of the Monitoring Plan.* For the Hg CEMS, sorbent trap monitoring systems, and any flow rate and/or moisture, and/or diluent gas monitors used to provide data under this subpart, the monitoring plan shall contain the following information, as applicable:

7.1.1.2.1 *Electronic.* Unit or stack IDs; monitoring location(s); type(s) of fuel combusted; type(s) of emission controls; maximum rated unit heat input(s); megawatt rating(s); monitoring methodologies used; monitoring system information (unique system and component ID numbers, parameters monitored); formulas used to calculate emissions and heat input; unit operating ranges and normal load level(s); monitor span and range information.

7.1.1.2.2 *Hard Copy.* Schematics and/or blueprints showing the location of monitoring systems and test ports; data flow diagrams; test protocols; monitor span and range calculations; miscellaneous technical justifications.

7.1.2 *Operating Parameter Records. T*he owner or operator shall record the following information for each operating hour of each affected unit and each non-affected unit under section 2.3 of this appendix, and also for each group of units utilizing a common stack, to the extent that these data are needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section:

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWge);

7.1.2.4 The hourly heat input rate (MMBtu/hr, rounded to the nearest tenth);

7.1.2.5 An identification code for the formula used to calculate the hourly heat input rate, as provided in the monitoring plan; and

7.1.2.6 The F-factor used for the heat input rate calculation.

7.1.3 *Hg Emissions Records (Hg CEMS).* For each affected unit or common stack using a Hg CEMS, the owner or operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (µg/scm, rounded to the nearest tenth);

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour; and

7.1.3.5 Monitor availability, as a percentage of unit or stack operating hours.

7.1.4 *Hg Emissions Records (Sorbent Trap Monitoring Systems).* For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (µg/scm, rounded to the nearest tenth). Note that when a quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, e.g., liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Data availability, as a percentage of unit or stack operating hours.

7.1.5 *Stack Gas Volumetric Flow Rate Records.*

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems, to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification 12B in Appendix B to part 60 of this chapter). Stack gas flow rate data are also needed in order to demonstrate compliance with heat input-based and electrical output-based Hg emissions limits, as provided in sections 6.2.1 and 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if measurements of stack gas flow rate are required, use a certified flow rate monitor to record the following information for each unit or stack operating hour:

7.1.5.2.1 The date and hour;

7.1.5.2.2 Monitoring system and component identification codes, as provided in the monitoring plan, if a quality-assured flow rate value is obtained for the hour;

7.1.5.2.3 The hourly average volumetric flow rate, if a quality-assured flow rate value is obtained for the hour (in scfh, rounded to the nearest thousand);

7.1.5.2.4 A special code, indicating whether or not a quality-assured flow rate value is obtained for the hour; and

7.1.5.2.5 Monitor availability, as a percentage of unit or stack operating hours.

7.1.6 *Records of Stack Gas Moisture Content.*

7.1.6.1 Correction of Hg concentration data for moisture is sometimes required, when compliance with an applicable Hg emissions limit must be demonstrated, as provided in sections 6.2.1 and 6.2.2 of this appendix. In particular, these corrections are required for sorbent trap monitoring systems and for Hg CEMS that measure Hg concentration on a dry basis.

7.1.6.2 If moisture corrections are required, use a certified moisture monitoring system to record the following information for each unit or stack operating hour (except where a default moisture value is used; in that case, keep a record of the default value currently in use):

7.1.6.2.1 The date and hour;

7.1.6.2.2 Monitoring system and component identification codes for the system, as provided in the monitoring plan, if a quality-assured moisture value is obtained for the hour;

7.1.6.2.3 Hourly average moisture content of the flue gas (percent H_2O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the wet- and dry-basis oxygen hourly averages (in percent O_2, rounded to the nearest tenth);

7.1.6.2.4 A special code, indicating whether or not a quality-assured moisture value is obtained for the hour; and

7.1.6.2.5 Monitor availability, as a percentage of unit or stack operating hours.

7.1.7 *Records of Diluent Gas (CO_2 or O_2) Concentration.*

7.1.7.1 When a heat input-based Hg mass emissions limit must be met (e.g., in units of lb/TBtu), hourly measurements of CO_2 or O_2 concentration are required, in order to calculate hourly heat input values.

7.1.7.2 For each affected unit or common stack, if measurements of diluent gas concentration are required, use a certified CO_2 or O_2 monitor to record the following information for each unit or stack operating hour:

7.1.7.2.1 The date and hour;

7.1.7.2.2 Monitoring system and component identification codes, as provided in the monitoring plan, if a quality-assured O_2 or CO_2 concentration is obtained for the hour;

7.1.7.2.3 The hourly average O_2 or CO_2 concentration (in percent, rounded to the nearest tenth);

7.1.8.2.4 A special code, indicating whether or not a quality-assured O_2 or CO_2 concentration value is obtained for the hour; and

7.1.7.2.5 Monitor availability, as a percentage of unit or stack operating hours.

7.1.8 *Hg Mass Emissions Records.* When compliance with a Hg emission limit in units of lb/GWh is required, Hg mass emissions must be calculated. In such cases, record the following information for each operating hour of affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The calculated hourly Hg mass emissions, from Equation A–2 or A–3 in section 6.2.2 of this appendix (lb, rounded to three decimal places), if valid values of Hg concentration, stack gas volumetric flow rate, and (if applicable) moisture data are all obtained for the hour;

7.1.8.3 An identification code for the formula (either Equation A–2 or A–3 in section 6.2.2 of this appendix) used to calculate hourly Hg mass emissions from Hg concentration, flow rate and (if applicable) moisture data; and

7.1.8.4 A code indicating that the Hg mass emissions were not calculated for the hour, if valid data for Hg concentration, flow rate, and/or moisture (as applicable) are not obtained for the hour.

7.1.9 *Hg Emission Rate Records.* For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.9.1 The date and hour;

7.1.9.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable, rounded to three decimal places), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

7.1.9.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A–4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.9.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour.

7.1.10 *Certification and Quality Assurance Test Records.* For the continuous monitoring systems used to provide data under this subpart at each affected unit (or group of units monitored at a common stack) and each non-affected unit under section 2.3 of this appendix, record the following certification and quality-assurance information:

7.1.10.1 The reference values, monitor responses, and calculated calibration error (CE) values, for all required 7-day calibration error tests and daily calibration error tests of all volumetric flow rate monitors and gas monitors, including Hg CEMS;

7.1.10.2 The results (pass/fail) of the required daily interference checks of flow monitors;

7.1.10.3 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all required linearity checks of all gas monitors, including Hg CEMS, and for all single-level and 3-level system integrity checks of Hg CEMS;

7.1.10.4 The results (pass/fail) of all required quarterly leak checks of all differential pressure-type flow monitors (if applicable);

7.1.10.5 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of all Hg CEMS, sorbent trap monitoring systems, and (as applicable) flow rate, diluent gas, and moisture monitoring systems;

7.1.10.6 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of all gas monitors, including Hg CEMS;

7.1.10.7 Supporting information for all required RATAs of volumetric flow rate monitoring systems, diluent gas monitoring systems, and moisture monitoring systems, including the raw field data and, as applicable, the results of reference method bias and drift checks, calibration gas certificates, the results of lab analyses, and records of sampling equipment calibrations. For the RATAs of Hg CEMS and sorbent trap monitoring systems, keep sufficient records of the test dates, the raw reference method and monitoring system data, and the results of sample analyses to substantiate the reported test results; and

7.1.10.8 For sorbent trap monitoring systems, the results of all analyses of the sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B–1 of Performance Specification 12B in Appendix B to part 60 of this chapter.

7.2 *Reporting Requirements.*

7.2.1 *General Reporting Provisions.* The owner or operator shall comply with the following reporting requirements for each affected unit (or group of units monitored at a common stack) and each non-affected unit under section 2.3 of this appendix:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

7.2.2 *Notifications.* In addition to the notifications required elsewhere in this subpart, the owner or operator of any affected unit shall provide the following notifications for each affected unit (or group of units monitored at a common stack) and each non-affected unit under section 2.3 of this appendix. Provide each notification at least 21 days prior to the event:

7.2.2.1 The date(s) of the required annual RATAs of the Hg CEMS, sorbent trap monitoring systems, and (as applicable) flow rate, diluent gas, and moisture monitoring systems used to provide data under this subpart;

7.2.2.2 The date on which emissions first exhaust through a new stack or flue gas desulfurization system; and

7.2.2.3 The date on which an affected unit is removed from service and placed into long-term cold storage, and the date on which the unit is expected to resume operation.

7.2.3 *Monitoring Plan Reporting.* The owner or operator of any affected unit shall make electronic and hard copy monitoring plan submittals for each affected unit (or group of units monitored at a common stack) and each non-affected unit under section 2.3 of this appendix, as follows:

7.2.3.1 At least 21 days prior to the initial certification testing or recertification testing of a monitoring system used to provide data under this subpart; and

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.4 The results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.10.3 through 7.1.10.6 of this section shall be submitted electronically, either prior to or concurrent with the relevant quarterly electronic report.

7.2.5 *Quarterly Reports.*

7.2.5.1 Beginning with the calendar quarter containing the program start date, the owner or operator of any affected unit shall submit electronic quarterly reports to the Administrator, in a format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) and each non-affected unit under section 2.3 of this appendix.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.19 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

7.2.5.3.4 The results of all daily calibration error tests and daily flow monitor interference checks, as described in paragraphs 7.1.10.1 and 7.1.10.2 of this section.

7.2.5.4 Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, stratification test results, sampling equipment calibrations, quality control plan information) is excluded from electronic reporting.

7.2.5.5 *Compliance Certification.* The owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report, based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) and (if applicable) any non-affected unit(s) under section 2.3 of this appendix have been correctly and fully monitored. The compliance certification shall indicate whether the monitoring data submitted were recorded in accordance with the applicable requirements of this appendix.

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