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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2002–0058; FRL–9148–5]

RIN 2060–AG69

National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: On September 13, 2004, under authority of section 112 of the Clean Air Act, EPA promulgated national emission standards for hazardous air pollutants for new and existing industrial/commercial/institutional boilers and process heaters. On June 19, 2007, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded the national emission standards for hazardous air pollutants for industrial/commercial/institutional boilers and process heaters.

In response to the court's vacatur and remand, this action would require all major sources to meet hazardous air pollutants emissions standards reflecting the application of the maximum achievable control technology. The proposed rule would protect air quality and promote public health by reducing emissions of the hazardous air pollutants listed in section 112(b)(1) of the Clean Air Act.

We are also proposing that existing major source facilities with an affected boiler undergo an energy assessment on the boiler system to identify cost-effective energy conservation measures.

DATES: Comments must be received on or before July 19, 2010. Under the Paperwork Reduction Act, 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 July 6, 2010.

Public Hearing. We will hold a public hearing concerning this proposed rule and the interrelated proposed Boiler area source, CISWI, and RCRA rules, discussed in this proposal and published in the proposed rules section of today's **Federal Register**, on June 21, 2010. Persons requesting to speak at a public hearing must contact EPA by June 14, 2010.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2002–0058, 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 Docket ID No. EPA–HQ–OAR–2002–0058.
- *Fax:* Fax your comments to: (202) 566–9744, Docket ID No. EPA–HQ–OAR–2002–0058.
- *Mail: Send your comments to:* EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Docket ID No. EPA–HQ–OAR–2002–0058. 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 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.

Public Hearing: We will hold a public hearing concerning this proposed rule on June 21, 2010. Persons interested in presenting oral testimony at the hearing should contact Ms. Pamela Garrett, Energy Strategies Group, at (919) 541–7966 by June 14, 2010. The public hearing will be held in the Washington DC area at a location and time that will be posted at the following Web site: *http://www.epa.gov/airquality/combustion.* Please refer to this Web site to confirm the date of the public hearing as well. If no one requests to speak at the public hearing by June 14, 2010 then the public hearing will be cancelled and a notification of cancellation posted on the following Web site: *http://www.epa.gov/airquality/combustion.*

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 Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Brian Shrager, 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) 541–7689; Fax number (919) 541–5450; *E-mail address: shrager.brian@epa.gov.*

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

I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by the proposed standards include:

Category	NAICS code [1]	Examples of potentially regulated entities
Any industry using a boiler or process heater as defined in the proposed rule.	211	Extractors of crude petroleum and natural gas.
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refineries, and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational services.

[1] North American Industry Classification System.

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 63.7485 of subpart DDDDD (National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institution Boilers and Process Heaters). 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 63.13 of subpart A (General Provisions).

B. 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–2002–0058. 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.

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

In addition to being available in the docket, an electronic copy of this proposed action will also be available on the World Wide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of the proposed action 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.

D. When would a public hearing occur?

We will hold a public hearing concerning this proposed rule on June 21, 2010. Persons interested in presenting oral testimony at the hearing should contact Ms. Pamela Garrett, Energy Strategies Group, at (919) 541–7966 by June 14, 2010. The public hearing will be held in the Washington, DC area at a location and time that will be posted at the following Web site: *http://www.epa.gov/airquality/combustion.* Please refer to this Web site to confirm the date of the public hearing as well. If no one requests to speak at the public hearing by June 14, 2010, then the public hearing will be cancelled and a notification of cancellation posted on the following Web site: *http://www.epa.gov/airquality/combustion.*

II. Background Information

A. What is the statutory authority for this proposed rule?

Section 112(d) of the Clean Air Act (CAA) requires EPA to set emissions standards for hazardous air pollutants (HAP) emitted by major stationary sources based on the performance of the maximum achievable control technology (MACT). 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 (for which the Administrator has emissions information) or the best performing 5 sources for source categories with less than 30 sources (CAA section 112(d)(3)(A) and (B)). This level of minimum stringency is called the MACT 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 (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 environmental impacts when doing so.

CAA section 112(c)(6) requires EPA to list categories and subcategories of sources assuring that sources accounting for not less than 90 percent of the aggregate emissions of each such pollutant (alkylated lead compounds; polycyclic organic matter; hexachlorobenzene; mercury; polychlorinated byphenyls; 2,3,7,8-tetrachlorodibenzofurans; and 2,3,7,8-tetrachloroidibenzo-p-dioxin) are subject to standards under subsection 112(d)(2) or (d)(4). Standards established under CAA section 112(d)(2) must reflect the performance of MACT. "Industrial Coal Combustion," "Industrial Oil Combustion," "Industrial Wood/Wood Residue Combustion," "Commercial Coal Combustion," "Commercial Oil Combustion," and "Commercial Wood/Wood Residue Combustion" are listed as source categories for regulation pursuant to CAA section 112(c)(6) due to emissions of polycyclic organic matter (POM) and mercury (63 FR 17838, 17848, April 10, 1998). In the documentation for the 112(c)(6) listing, the commercial fuel combustion categories included institutional fuel combustion ("1990 Emissions Inventory of Section 112(c)(6) Pollutants, Final Report," April 1998).

CAA section 129(a)(1)(A) requires EPA to establish specific performance standards, including emission limitations, for "solid waste incineration units" generally, and, in particular, for "solid waste incineration units combusting commercial or industrial waste" (section 129(a)(1)(D)). Section 129 defines "solid waste incineration unit" as "a distinct operating unit of any facility which combusts any solid waste material from commercial or industrial establishments or the general public." Section 129(g)(1). Section 129 also provides that "solid waste" shall have the meaning established by EPA pursuant to its authority under the Resource Conservation and Recovery Act. Section 129(g)(6).

In *Natural Resources Defense Council* v. *EPA,* 489 F. 3d 1250, 1257–61 (DC Cir. 2007), the court vacated the Commercial and Industrial Solid Waste Incineration (CISWI) Definitions Rule, 70 FR 55568 (September 22, 2005), which EPA issued pursuant to CAA section 129(a)(1)(D). In that rule, EPA defined the term "commercial or industrial solid waste incineration unit" to mean a combustion unit that combusts "commercial or industrial waste." The rule defined "commercial or industrial waste" to mean waste combusted at a unit that does not recover thermal energy from the combustion for a useful purpose. Under these definitions, only those units that combusted commercial or industrial waste and were not designed to, or did not operate to, recover thermal energy from the combustion would be subject to section 129 standards. The District of Columbia Circuit (DC Circuit) rejected the definitions contained in the CISWI Definitions Rule and interpreted the term "solid waste incineration unit" in CAA section 129(g)(1) "to unambiguously include among the incineration units subject to its standards any facility that combusts any commercial or industrial solid waste material at all—subject to the four statutory exceptions identified in [CAA section 129(g)(1).]" *NRDC* v. *EPA,* 489 F.3d 1250, 1257–58.

CAA section 129 covers any facility that combusts any solid waste; CAA section 112(g)(6) directs the Agency to the Resource Conservation and Recovery Act (RCRA) in terms of the definition of solid waste. The Agency is in the process of defining solid waste for purposes of Subtitle D of RCRA. EPA initiated a rulemaking to define which secondary materials are "solid waste" for purposes of subtitle D (nonhazardous waste) of RCRA when burned in a combustion unit. (See Advance Notice of Proposed Rulemaking (74 FR 41, January 2, 2009) soliciting comment on whether certain secondary materials used as alternative fuels or ingredients are solid wastes within the meaning of Subtitle D of RCRA.) If a unit combusts solid waste, it is subject to CAA section 129 of the Act, unless it falls within one of the four specified exceptions in CAA section 129(g).

The solid waste definitional rulemaking under RCRA is being proposed in a parallel action and is relevant to this proceeding because some industrial, commercial, or institutional boilers and process heaters combust secondary materials as alternative fuels. If industrial, commercial, or institutional boilers or process heaters combusts secondary materials that are solid waste under the proposed definitional rule, those units would be subject to section 129. The units subject to this rule include those industrial, commercial, or institutional boilers and process heaters that do not combust solid waste. EPA recognizes that it has imperfect information on the exact nature of the secondary materials which boilers and process heaters combust, including, for example, how much processing of such materials occurs, if any. We nevertheless used the information currently available to the Agency to determine which materials are solid waste and, therefore, subject to CAA section 129, and which are not solid waste and, therefore, subject to CAA section 112.

B. Summary of the Natural Resources Defense Council v. *EPA Decision*

On September 13, 2004, EPA issued the NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR 55218) (the Boiler MACT). We identified 18 subcategories of boilers and process heaters emitting four different types of HAPs. *See* 69 FR 55,223–24. EPA set out to establish the MACT floor for each subcategory emitting each HAP according to the effectiveness of various add-on technologies. (*See* 68 FR 1660, 1674, Jan. 13, 2003 (proposed rule).) Applying this methodology, EPA set 25 numerical emission standards. The 2004 final rule established emission limitations for particulate matter (PM), as a surrogate for non-mercury HAP metals, mercury, and hydrogen chloride (HCl), as a surrogate for acid gas HAP, for existing large solid fuel-fired sources only. For the remaining 47 boiler subcategory/HAP emissions, EPA determined that the appropriate MACT floor was “no emissions reduction” because “the best-performing sources were not achieving emissions reductions through the use of an emission control system and there were no other appropriate methods by which boilers and process heaters could reduce HAP emissions.” (69 FR 55,233.) Accordingly, we established no standards. In addition, we set risk-based standards, also known as health-based compliance alternatives, as alternatives to the MACT-based standards for hydrogen chloride and manganese.

EPA issued emissions standards for CISWI units on December 1, 2000, and as part of that rulemaking, defined the term “commercial and industrial waste” to mean solid waste combusted in an enclosed device using controlled flame combustion without energy recovery that is a distinct operating unit of any commercial or industrial facility. In response to a petition for reconsideration, EPA filed a motion for voluntary remand, which the court granted on September 6, 2001. On remand, EPA solicited comments on the CISWI Rule’s definitions of “solid waste,” “commercial and industrial waste” and “CISWI unit.” On September 22, 2005, EPA issued the CISWI Definitions Rule, which contained definitions that were substantively the same as those issued before reconsideration. In particular, the 2005 CISWI Definitions Rule defined “commercial or industrial waste” to include only waste that is combusted at a facility that cannot or does not use a process that recovers thermal energy from the combustion for a useful purpose.

EPA received separate petitions from environmental groups, industry, and municipalities seeking judicial review of the NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT) as well as amendments to definitional terms in the Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units (CISWI Definitions Rule), promulgated pursuant to CAA section 129. The environmental organizations challenged the CISWI Definitions Rule on the ground that its definition of “commercial or industrial waste” was inconsistent with the plain language of CAA section 129 and therefore impermissibly constricted the class of “solid waste incineration unit[s]” that were subject to the emission standards of the CISWI Rule. The environmental groups also challenged specific emission standards that EPA promulgated in the Boiler MACT and EPA’s methodology for setting them. The municipalities—the American Municipal Power-Ohio, Inc. and six of its members, the cities of Dover, Hamilton, Orrville, Painesville, Shelby and St. Mary’s—challenged the Boiler MACT on the grounds that EPA failed to comply with the requirements of the Regulatory Flexibility Act (RFA) and that the standards as applied to small municipal utilities are unlawful.

As explained further below, the Court concluded that EPA’s definition of “commercial or industrial waste,” as incorporated in the definition of “commercial and industrial solid waste incineration unit” (CISWI unit), was inconsistent with the plain language of CAA section 129 and that the CISWI Definitions Rule must, therefore, be vacated. The Court also vacated and remanded the Boiler MACT, finding that the Boiler MACT must be substantially revised as a consequence of the vacatur and remand of the CISWI Definitions Rule.

In its decision, the Court agreed with the environmental petitioners that EPA’s definition of “commercial or industrial waste,” as incorporated in the definition of CISWI units, conflicted with the plain language of CAA section 129(g)(1). That provision defines “solid waste incineration unit” to mean “any facility which combusts any solid waste material” from certain types of establishments, with four specific exclusions. The Court stated that, based on the use of the term “any” and the specific exclusions for only certain types of facilities from the definition of “solid waste incineration unit,” CAA section 129 unambiguously includes among the incineration units subject to its standards any facility that combusts any commercial or industrial solid waste material at all—subject only to the four statutory exclusions. The Court held that the definitions EPA promulgated in the CISWI Definitions Rule constricted the plain language of CAA section 129(g)(1), because the CISWI Definitions Rule excluded from its universe operating units that combusted solid waste and were designed for or operating with energy recovery.

Having determined that EPA’s definition of “commercial and industrial solid waste incineration unit” conflicts with the plain meaning of CAA section 129 and must, therefore, be vacated, the Court also vacated the Boiler MACT because it concluded that the Boiler MACT would need to be revised because the universe of boilers subject to its standards will be different once EPA revises the CISWI definitions rule consistent with the Court’s opinion. The Court did not address petitioners’ specific challenges to the Boiler MACT.

C. Summary of Other Related 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) MACT standards 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 Court reiterated its prior holdings, including National Lime Association, confirming that EPA must set floor standards for all HAP emitted by the major 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 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)

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 Ass'n,* 233 F. 3d at 640.)

The Brick MACT decision also stated that EPA may account for variability in setting floors. However, the court found that EPA erred in assessing variability because it relied on data from the worst performers to estimate best performers' variability, and held 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.)

The majority opinion in the Brick MACT case does not address the possibility of subcategorization to address differences in the HAP content of raw materials. However, in his concurring opinion Judge Williams stated that EPA's ability to create subcategories for sources of different classes, size, or type (CAA section 112(d)(1)) may provide a means out of the situation where the floor standards are achieved for some sources, but the same floors cannot be achieved for other sources due to differences in local raw materials whose use is essential. (*Id.* At 884–85.9)

A second court opinion is also relevant to this proposal. In *Sierra Club* v. *EPA,* 551 F. 3d 1019 (DC Cir. 2008), the court vacated the portion of the regulations contained in the General Provisions which exempt major sources from MACT standards 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." The vacated Boiler MACT did not contain specific provisions covering operation during SSM operating modes; rather it referenced the now-vacated exemption in the General Provisions. As a result of the court decision, we are addressing SSM in this proposed rulemaking. Discussion of this issue may be found later in this preamble.

D. EPA's Response to the Vacatur

In response to the *NRDC* v. *EPA* mandate, we initiated an information collection effort entitled "Information Collection Effort for Facilities with Combustion Units." This information collection was conducted by EPA's Office of Air and Radiation pursuant to CAA section 114 to assist the Administrator in developing emissions standards for boilers/process heaters and CISWI units (collectively, "combustion units") pursuant to CAA sections 112(d) and 129. 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 * * *

There were two components to the information collection. To obtain the information necessary to identify and categorize all combustion units potentially affected by the revised standards for boilers/process heaters and for CISWI units, the first component of the information collection effort solicited information from all potentially affected combustion units in the format of an electronic survey. The survey was submitted to the following facilities: (1) All facilities that submitted an initial notification for the 2004 boiler MACT standard, (2) all facilities identified by States as being subject to the 2004 boiler MACT standard, and (3) facilities that are classified as a major source in their Title V permit that have a boiler or process heater listed in their permit. The survey was also sent to units covered by the 2000 CISWI emissions standards (40 CFR part 60 subpart CCCC) and to facilities that have incineration units (e.g., energy recovery units) that were listed as exempt under the 2000 CISWI standard. Each facility was required to complete the survey for all combustion units located at the facility. The information requested for each combustion unit included the unit design, operation, air pollution control data, the fuels/materials burned, and available emissions test data, continuous emission monitoring (CEM) data, fuel/material analysis data, and permitted and regulatory emission limits.

The second component of the information collection request effort consisted of requiring the owners/operators of 169 boilers/process heaters to conduct emission testing for HAP and HAP surrogates. We first analyzed the results of the survey to determine if sufficient emissions data existed to develop emission standards under CAA sections 112(d) for all types of boilers/process heaters, all types of materials combusted, and all HAP to be regulated. If data were not sufficient, then we selected pools of candidates to conduct emission testing. We submitted a list of candidates to stakeholders, including state, industry, and environmental stakeholders, who had an opportunity to comment on the technical feasibility, the least-cost impact of the testing program, and the appropriateness of the testing being requested. We then made a selection of test sites after taking into account stakeholder comments. The sites selected were required to conduct an outlet stack test, consisting of three runs, in accordance with EPA-approved protocols, for all of the following pollutants: PM (filterable, condensable, and $PM_{2.5}$), dioxins/furans (D/F), hydrogen chloride/hydrogen fluoride, mercury, metals (including antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus, and selenium), carbon monoxide (CO), total hydrocarbons (THC), formaldehyde, oxides of nitrogen (NO_X), and sulfur dioxide (SO_2). Six facilities (two coal-fired, two biomass-fired, and two gas-fired boilers) were required to collect CEM data over 30 operating days using mobile CEM devices for CO, THC, and NO_X. The owner/operator of each selected combustion unit was also required to collect and analyze, in accordance with acceptable procedures, the material(s) fed to the combustion unit during each stack test. The results of the stack tests and the analyses of materials combusted were required to be submitted to the Agency and are available in the docket and can be downloaded at *http://www.epa.gov/ttn/atw/boiler/boilerpg.html.*

When we compared information on boilers and process heaters from facilities submitting initial notifications to comply with the vacated 2004 Boiler MACT to the information gathering effort conducted for the 2004 Boiler MACT, a large disparity was identified in the number of potentially affected units at major sources of HAP. Since the last combustion unit data gathering effort in 1996, many sources have shut down, others have selected to operate with a permit limit on their HAP emissions in order to avoid being subject to the Boiler MACT (i.e., synthetic area source), and some units have switched out older solid fuel units for newer equipment due to increased insurance and maintenance costs.

Based on the definition of solid waste as set forth in a parallel proposed action, we revised the population of combustion units subject to CAA section 129 (because they combust solid waste) and the population of boilers and process heaters subject to CAA section 112 (because they do not combust solid waste). We then used the new data to develop a revised NESHAP for boilers and process heaters under CAA section 112 and revised standards for incineration units covered by CAA section 129. Specifically, the data provide the Agency with updated information on the number of potentially affected units, available emission test data, and fuel/material analysis data to address variability. We are using all of the information before the Administrator to calculate the MACT floors, set emission limits, and evaluate the emission impacts of various regulatory options for these revised rulemakings.

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

The proposed rule regulates source categories covering industrial boilers, institutional boilers, commercial boilers, and process heaters. These source categories potentially include combustion units that are already regulated by other MACT standards. Therefore, we are excluding from this proposed rule any boiler or process heater that is subject to regulation under other MACT standards.

In 1986, EPA had codified new source performance standards (NSPS) for industrial boilers (40 CFR part 60, subparts Db and Dc) and revised portions of those standards in 1999 and 2006. The NSPS regulates emissions of PM, SO_2, and NO_X from boilers constructed after June 19, 1984. Sources subject to the NSPS will be subject to the final CAA section 112(d) standards for boilers and process heaters because it regulates sources of HAP while the NSPS do not. However, in developing the proposed rule, we considered the monitoring requirements, testing requirements, and recordkeeping requirements of the NSPS to avoid duplicating requirements.

This proposed rule addresses the combustion of non-solid waste materials in boilers and process heaters. If an owner or operator of an affected source subject to these proposed standards were to start combusting a solid waste (as defined by the Administrator under RCRA), the affected source would cease to be subject to this action and would instead be subject to regulation under CAA section 129. A rulemaking under CAA section 129 is being proposed in a parallel action and is relevant to this action because it would apply to boilers and process heaters located at a major source that combust any solid waste. EPA is taking comment on whether a boiler or process heater could then opt back into regulation under this proposed rule by taking a federally enforceable restriction precluding the future combustion of any solid waste material.

F. What are the health effects of pollutants emitted from industrial/commercial/institutional boilers and process heaters?

This proposed rule protects air quality and promotes the public health by reducing emissions of some of the HAP listed in CAA section 112(b)(1). As noted above, emissions data collected during development of the proposed rule show that hydrogen chloride emissions represent the predominant HAP emitted by industrial, commercial, and institutional (ICI) boilers, accounting for 61 percent of the total HAP emissions.[1] ICI boilers and process heaters also emit lesser amounts of hydrogen fluoride, accounting for about 17 percent of total HAP emissions, and metals (arsenic, cadmium, chromium, mercury, manganese, nickel, and lead) accounting for about 6 percent of total HAP emissions. Organic HAP (formaldehyde, POM, acetaldehyde, benzene) account for about 15 percent of total HAP emissions. Exposure to these HAP, depending on exposure duration and levels of exposures, can be associated with a variety of adverse health effects. These adverse health effects may include, for example, irritation of the lung, skin, and mucus membranes, effects on the central nervous system, damage to the kidneys, and alimentary effects such as nausea and vomiting. We have classified two of the HAP as human carcinogens (arsenic and chromium VI) and four as probable human carcinogens (cadmium, lead, dioxins/furans, and nickel). We do not know the extent to which the adverse health effects described above occur in the populations surrounding these facilities. However, to the extent the adverse effects do occur, this proposed rule would reduce emissions and subsequent exposures.

III. Summary of This Proposed Rule

This section summarizes the requirements proposed in today's action. Section IV below provides our rationale for the proposed requirements.

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

This proposed rule affects industrial boilers, institutional boilers, commercial boilers, and process heaters. In this proposed rule, process heaters are defined as units in which the combustion gases do not directly come into contact with process material or gases in the combustion chamber (e.g., indirect fired). Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water.

B. What is the affected source?

The affected source is: (1) The collection of all existing industrial, commercial, or institutional boilers or process heaters within a subcategory located at a major source facility that do not combust solid waste or (2) each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source facility that do not combust solid waste, as that term is defined by the Administrator under RCRA.

The affected source does not include boilers and process heaters that are subject to another standard under 40 CFR part 63 or a standard established under CAA section 129.

C. Does this proposed rule apply to me?

This proposed rule applies to you if you own or operate a boiler or process heater at a major source meeting the requirements discussed previously in this preamble. A major source of HAP emissions is any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the

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[1] *See* Memorandum "Methodology for Estimating Impacts from Industrial, Commercial, Institutional Boilers and Process Heaters at Major Sources of Hazardous Air Pollutant Emissions" located in the docket.

potential to emit considering controls 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP.

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

We are proposing the emission limits presented in Table 1 of this preamble. Emission limits were developed for new and existing sources for eleven subcategories, which we developed based on unit design.

We are proposing that if your new or existing boiler or process heater burns at least 10 percent coal on an annual average heat input[2] basis, the unit is in one of the coal subcategories. If your new or existing boiler or process heater burns at least 10 percent biomass, on an annual average heat input basis, and less than 10 percent coal, on an annual average heat input basis, we are proposing that the unit is in one of the biomass subcategories. If your new or existing boiler or process heater burns at least 10 percent liquid fuel (such as distillate oil, residual oil), and less than 10 percent solid fuel, on an annual heat input basis, we are proposing that the unit is in the liquid subcategory. If your new or existing boiler or process heater burns gaseous fuel and less than 10 percent, on an annual average heat input basis, of liquid or solid fuel, we are proposing that the unit is in one of the gas subcategories.

TABLE 1—EMISSION LIMITS FOR BOILERS AND PROCESS HEATERS

[Pounds per million British thermal units]

Subcategory	Particulate matter (PM)	Hydrogen chloride (HCl)	Mercury (Hg)	Carbon monoxide (CO) (ppm @3% oxy-gen)	Dioxins/furans (total TEQ) (ng/dscm)
Existing—Coal Stoker	0.02	0.02	0.000003	50	0.003
Existing—Coal Fluidized Bed	0.02	0.02	0.000003	30	0.002
Existing—Pulverized Coal	0.02	0.02	0.000003	90	0.004
Existing—Biomass Stoker	0.02	0.006	0.0000009	560	0.004
Existing—Biomass Fluidized Bed	0.02	0.006	0.0000009	250	0.02
Existing—Biomass Suspension Burner/Dutch Oven	0.02	0.006	0.0000009	1010	0.03
Existing—Biomass Fuel Cells	0.02	0.006	0.0000009	270	0.02
Existing—Liquid	0.004	0.0009	0.000004	1	0.002
Existing—Gas (Other Process Gases)	0.05	0.000003	0.0000002	1	0.009
New—Coal Stoker	0.001	0.00006	0.000002	7	0.003
New—Coal Fluidized Bed	0.001	0.00006	0.000002	30	0.00003
New—Pulverized Coal	0.001	0.00006	0.000002	90	0.002
New—Biomass Stoker	0.008	0.004	0.0000002	560	0.00005
New—Biomass Fluidized Bed	0.008	0.004	0.0000002	40	0.007
New—Biomass Suspension Burner/Dutch Oven	0.008	0.004	0.0000002	1010	0.03
New—Biomass Fuel Cells	0.008	0.004	0.0000002	270	0.0005
New—Liquid	0.002	0.0004	0.0000003	1	0.002
New—Gas (Other Process Gases)	0.003	0.000003	0.0000002	1	0.009

The proposed emission limits in the above table apply only to existing boilers and process heaters that have a designed heat input capacity of 10 million British thermal units (Btu) per hour or greater. Pursuant to CAA section 112(h), we are proposing a work practice standard for three particular classes of boilers and process heaters: Existing units that have a designed heat input capacity of less than 10 million Btu per hour and new and existing units in the Gas 1 (natural gas/refinery gas) subcategory and in the metal process furnaces subcategory. The work practice standard being proposed for these boilers and process heaters would require the implementation of a tune-up program as described in section III.F of this preamble.

We are also proposing a beyond-the-floor standard for all existing major source facilities having affected boilers or process heaters that would require the performance of a one-time energy assessment, as described in section III.F of this preamble, by qualified personnel, on the affected boilers and facility to identify any cost-effective energy conservation measures.

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

The United States Court of Appeals for the District of Columbia Circuit vacated portions of two provisions in EPA's CAA Section 112 regulations governing the emissions of HAP during periods of startup, shutdown, and malfunction (SSM). *Sierra Club* v. *EPA,* 551 F.3d 1019 (DC Cir. 2008), *cert. denied, 2010 U.S. LEXIS 2265 (2010).* Specifically, the 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 section 112 of the CAA. 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* v. *EPA,* EPA has established standards in this rule that apply at all times. EPA has attempted to ensure that we have not incorporated into proposed regulatory language any provisions that are inappropriate, unnecessary, or redundant in the absence of an SSM exemption. We are specifically seeking comment on whether there are any such provisions that we have inadvertently incorporated or overlooked. We also request comment on whether there are additional provisions that should be added to regulatory text in light of the absence of an SSM exemption and provisions related to the SSM exemption (such as the SSM plan requirement and SSM recordkeeping and reporting provisions).

In establishing the standards in this rule, EPA has taken into account startup and shutdown periods and, for the

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[2] Heat input means heat derived from combustion of fuel in a boiler or process heater 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 kilns).

reasons explained below, has not established different standards for those periods. The standards that we are proposing are daily or monthly averages. Continuous emission monitoring data obtained from best performing units, and used in establishing the standards, include periods of startup and shutdown. Boilers, especially solid fuel-fired boilers, do not normally startup and shutdown more the once per day. Thus, we are not establishing a separate emission standard for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards. Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operation. We have evaluated whether it is appropriate to have the same standards apply during startup and shutdown as applied to normal operations.

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. It is reasonable to interpret section 112(d) as not requiring EPA to account for malfunctions in setting emissions standards. For example, we note that 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 major source boilers and process heaters. 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 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 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." 40 CFR 63.2 (definition of malfunction).

F. What are the testing and initial compliance requirements?

We are proposing that the owner or operator of a new or existing boiler or process heater must conduct performance tests to demonstrate compliance with all applicable emission limits. Affected units would be required to conduct the following compliance tests where applicable:

(1) Conduct initial and annual stack tests to determine compliance with the PM emission limits using EPA Method 5 or 17.

(2) Conduct initial and annual stack tests to determine compliance with the mercury emission limits using EPA method 29 or ASTM–D6784–02 (Ontario Hydro Method).

(3) Conduct initial and annual stack tests to determine compliance with the HCl emission limits using EPA Method 26A or EPA Method 26 (if no entrained water droplets in the sample).

(4) Use EPA Method 19 to convert measured concentration values to pound per million Btu values.

(5) Conduct initial and annual test to determine compliance with the CO emission limits using either EPA Method 10 or a CO CEMS.

(6) Conduct initial and annual test to determine compliance with the D/F emission limits using EPA Method 23.

As part of the initial compliance demonstration, we are proposing that you monitor specified operating parameters during the initial performance tests that you would conduct to demonstrate compliance with the PM, mercury, D/F, and HCl emission limits. You would calculate the average parameter values measured during each test run over the three run performance test. The average of the three average values (depending on the parameter measured) for each applicable parameter would establish the 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 boilers and process heaters without wet or dry 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 boilers and process heaters with wet scrubbers, you must measure pressure drop and liquid flow rate of the scrubber during the performance test, and calculate the average value for each test run. The average of the three test run averages establishes your minimum site-specific pressure drop and liquid flow rate operating levels. If different average parameter levels are measured during the mercury, PM 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 average for each test run and the average value for the performance test. This establishes your minimum pH operating limit.

(3) For boilers and process heaters with sorbent injection, you would be required to measure the sorbent injection rate for each sorbent used during the performance tests for HCl, mercury, and D/F and calculate the average for each sorbent for each test run. The average of the three test run averages 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 mercury, HCl, and D/F tests, the average value for each sorbent becomes your site-specific operating limit.

(4) For boilers and process heaters with fabric filters in combination with wet scrubbers, you must measure the pH, pressure drop, and liquid flowrate of the wet scrubber during the performance test and calculate the average value for each test run. The minimum test run average establishes your site-specific pH, pressure drop, and liquid flowrate operating limits for the wet scrubber. Furthermore, the fabric filter must be operated such that

the bag leak detection system alarm does not sound more than 5 percent of the operating time during any 6-month period unless a CEMS is installed to measure PM.

(5) For boilers and process heaters with electrostatic precipitators (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 the ESP collection fields during the mercury and PM performance test. You would then be required to calculate the average value of these parameters for each test run. The average of the three test run averages would establish your site-specific minimum pH, pressure drop, and liquid flowrate operating limit for the wet scrubber and the minimum voltage and current operating limits for the ESP.

(6) For boilers and process heaters that choose to demonstrate compliance with the mercury emission limit on the basis of fuel analysis, you would be required to measure the mercury content of the inlet fuel that was burned during the mercury performance test. This value is your maximum fuel inlet mercury operating limit.

(7) For boilers and process heaters that choose to demonstrate compliance with the HCl emission limit on the basis of fuel analysis, you would be required to measure the chlorine content of the inlet fuel that was burned during the HCl performance test. This value is your maximum fuel inlet chlorine operating limit.

These proposed operating limits would not apply to owners or operators of boilers or process heaters having a heat input capacity of less than 10 million Btu per hour (MMBtu/h) or boilers or process heaters of any size which combust natural gas or refinery gas, as discussed in section IV.D.3 of this preamble. Instead, we are proposing that owners or operators of such boilers and process heaters submit to the delegated authority or EPA, as appropriate, if requested, documentation that a tune-up meeting the requirements of the proposed rule was conducted. We are proposing that, to comply with the work practice standard, a tune-up procedure include the following:

(1) Inspect the burner, and clean or replace any components of the burner as necessary,

(2) Inspect the flame pattern and make any adjustments to the burner necessary to optimize the flame pattern consistent with the manufacturer's specifications,

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

(4) Minimize total emissions of CO consistent with the manufacturer's specifications,

(5) Measure the concentration in the effluent stream of CO in ppmvd, before and after the adjustments are made,

(6) Submit an annual report containing the concentrations of CO in the effluent stream in ppmvd, and oxygen in percent dry basis, measured before and after the adjustments of the boiler, 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.

Further, all owners or operators of major source facilities having boilers and process heaters subject to this rule would be required to submit to the delegated authority or EPA, as appropriate, documentation that an energy assessment was performed, by qualified personnel, and the cost-effective energy conservation measures indentified. The procedures for an energy assessment are:

(1) Conduct a visual inspection of the boiler system.

(2) Establish operating characteristics of the facility, energy system specifications, operating and maintenance procedures, and unusual operating constraints,

(3) Identify major energy consuming systems,

(4) Review available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage,

(5) Identify a list of major energy conservation measures,

(6) Determine the energy savings potential of the energy conservation measures identified, and

(7) Prepare a comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

G. What are the continuous compliance requirements?

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

(1) For units combusting coal, biomass, or residual fuel oil (*i.e.,* No 4, 5 or 6 fuel oil) with heat input capacities of less than 250 million Btu per hour that do not use a wet scrubber, we are proposing that opacity levels be maintained to less than 10 percent (daily average) for existing and new units with applicable emission limits. Or, if the unit is controlled with a fabric filter, instead of continuous monitoring of opacity, the fabric filter must be continuously operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during any 6-month period (unless a PM CEMS is used).

(2) For units combusting coal, biomass, or residual oil with heat input capacities of 250 million Btu per hour or greater, we are proposing that PM CEMS be installed and operated and that PM levels (monthly average) be maintained below the applicable PM limit.

(3) For boilers and process heaters with wet scrubbers, we are proposing that you monitor pressure drop and liquid flow rate of the scrubber and maintain the 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.

(4) For boilers and process heaters with dry scrubbers, 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.

(5) For boilers and process heaters having heat input capacities of less than 250 million Btu per hour with an ESP in combination with a wet scrubber, we are proposing that you monitor the pH, pressure drop, and liquid flow rate of the wet scrubber and maintain the 12-hour block averages at or above the operating limits established during the HCl performance test and that you monitor the voltage and current of the ESP collection plates and maintain the 12-hour block averages at or above the operating limits established during the mercury or PM performance test.

(6) For units that choose to comply with either the mercury emission limit or the HCl emission limit based on fuel analysis rather than on performance stack testing, we are proposing that you maintain daily fuel records that demonstrate that you burned no new fuels or fuels from a new supplier such that the mercury content or the chlorine content of the inlet fuel was maintained at or below your maximum fuel mercury content operating limit or your 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 mercury input 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.

(7) For all boilers and process heaters, we are proposing that you maintain daily records of fuel use that demonstrate that you have burned no materials that are considered solid waste.

(8) For boilers and process heaters in any of the subcategories with heat input capacities greater than 100 MMBtu/h, we are proposing that you continuously monitor CO and maintain the average CO emissions at or below the applicable limit listed in Tables 1 or 2 of this proposed rule.

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 presents the procedure for submitting a request to the Administrator to use alternative monitoring.

H. 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.

Semiannual compliance reports, as required by § 63.10(e)(3) of subpart A, would be required only for semiannual reporting periods when a deviation from any of the requirements in the rule occurred, or any process changes occurred and compliance certifications were reevaluated.

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 10. Owners or operators of sources with units with heat input capacity of less than 10 MMBtu/h or units combusting natural gas or refinery gas must keep records of the dates and the results of each required boiler tune-up.

Records of either 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 source electing to comply with an emission limit based on fuel analysis for each 30-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 source with an applicable HCl emission limit.

(7) Calculations and supporting information of mercury fuel input, as required in this proposed rule, for each affected source with an applicable mercury 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 mercury fuel input demonstrated that the new fuel or new fuel mixture still meets the mercury fuel input levels, for each affected source with an applicable mercury emission limit.

(10) A copy of the results of all performance tests, fuel analysis, opacity observations, 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 reports and 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.

(5) Compliance reports semi-annually.

I. Submission of Emissions Test Results to EPA

The EPA must have performance test data to conduct effective reviews of CAA Section 112 and 129 standards, as well as for many other purposes including compliance determinations, emissions factor development, and annual emissions rate determinations. In conducting these required reviews, we have 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 emissions test data because of varied locations for data storage and varied data storage methods. One improvement that has occurred in recent years is the availability of stack test reports in electronic format as a replacement for cumbersome paper copies.

In this action, we are taking a step to improve data accessibility. Owners and operators of boilers and process heaters will be required to submit to an EPA electronic database an electronic copy of reports of certain performance tests required under this rule. Data entry will be through an electronic emissions test report structure called the Electronic Reporting Tool (ERT) that will be used by the EPA staff as part of the emissions testing project. The ERT was developed with input from stack testing companies who generally collect and compile performance test data electronically and offices within State and local agencies which perform field test assessments. The ERT is currently available, and access to direct data submittal to EPA's electronic emissions database (WebFIRE) will become available by December 31, 2011.

The requirement to submit source test data electronically to EPA will not require any additional performance testing and will apply to those performance tests conducted using test methods that are supported by ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. The Web site listed at the end of this section contains a listing of the pollutants and test methods supported by ERT. In addition, when a facility submits performance test data to WebFIRE, there will be no additional requirements for emissions test data compilation. Moreover, we believe industry will benefit from development of improved emissions factors, fewer follow-up information requests, and better regulation development as discussed below. The information to be reported is already required for the existing test methods and is necessary to evaluate the conformance to the test method.

One major advantage of submitting source test data through the ERT is that it provides a standardized method to compile and store much of the documentation required to be reported by this rule while clearly stating what testing information we require. Another important benefit of submitting these data to EPA at the time the source test is conducted is that it will substantially reduce the effort involved in data collection activities in the future. Specifically, because EPA would already have adequate source category data to conduct residual risk assessments or technology reviews, there would be fewer or less substantial data collection requests (*e.g.,* CAA Section 114 letters). This results 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).

State/local/Tribal agencies may also benefit in that their review may be more streamlined and accurate as the States will not have to re-enter the data to assess the calculations and verify the data entry. Finally, another benefit of submitting these data to WebFIRE electronically is that these data will improve greatly the overall quality of the existing and new emissions factors by supplementing the pool of emissions test data upon which the emissions factor is based and by ensuring that data are more representative of current industry operational procedures. A common complaint we hear from industry and regulators is that emissions factors are outdated or not representative of a particular source category. Receiving and incorporating data for most performance tests will ensure that emissions factors, when updated, represent accurately the most current operational practices. In summary, receiving test data already collected for other purposes and using them in the emissions factors development program will save industry, State/local/Tribal agencies, and EPA time and money and work to improve the quality of emissions inventories and related regulatory decisions.

As mentioned earlier, the electronic data base that will be used is EPA's WebFIRE, which is a Web site accessible through EPA's Technology Transfer Network (TTN). The WebFIRE Web site was constructed to store emissions test data for use in developing emissions factors. A description of the WebFIRE data base can be found at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.*

The ERT will be able to transmit the electronic report through EPA's Central Data Exchange (CDX) network for storage in the WebFIRE data base. Although ERT is not the only electronic interface that can be used to submit source test data to the CDX for entry into WebFIRE, it makes 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.*

IV. Rationale for This Proposed Rule

A. How did EPA determine which sources would be regulated under this proposed rule?

This proposed rule regulates source categories covering industrial boilers, institutional and commercial boilers, and process heaters. These source categories potentially include combustion units that are already regulated by other MACT standards under CAA sections 112 or 129. Therefore, we are excluding from this proposed rule any units that are subject to regulation in another MACT standard established under CAA section 112 or a standard established under CAA section 129.

The CAA specifically requires that fossil fuel-fired steam generating units of more than 25 megawatts that produce electricity for sale (*i.e.,* utility boilers) be reviewed separately by EPA. Consequently, this proposed rule would not regulate fossil fuel-fired utility boilers greater than 25 megawatts, but would regulate fossil fuel-fired units less than 25 megawatts and all utility boilers firing a non-fossil fuel that is not a solid waste.

The scope of the process heater source category is limited to only indirect-fired units.[3] Direct-fired units are covered in other MACT standards or rulemakings pertaining to industrial process operations. For example, lime kilns are covered by the Pulp and Paper NESHAP (40 CFR part 63, subpart S). Indirect-fired process heaters are similar to boilers in fuel use, emissions, and applicable controls, and, therefore, it is appropriate for EPA to combine this listed source category of units with the listed source categories of industrial boilers and commercial/institutional boilers for purposes of developing emission standards.

The proposed rule would not regulate hot water heaters, as defined in this proposed rule, because such units are not part of the listed source categories. Many industrial facilities have office buildings located onsite which use hot water heaters. Such hot water heaters, by their design and operation, could be considered boilers since hot water heaters meet the definition of a boiler as specified in the proposed rule, because they are enclosed devices that combust fuel for the purpose of recovery energy to heat water. However, hot water heaters are more appropriately described as residential-type boilers, not industrial, commercial, or institutional boilers because their output (*i.e.,* hot water) is intended for personal use rather than for use in an industrial, commercial, or institutional process. Moreover, since hot water heaters generally are small and use natural gas as fuel, their emissions are negligible compared to the emissions from the industrial operations that make such facilities major sources, and compared to boilers that are used for industrial, commercial, or institutional purposes. However, the primary reason that we are excluding hot water heaters is that hot water heaters are not part of the listed source category. Consequently, we are including a definition of hot water heaters that includes fuel, size, pressure and temperature limitations that we believe are appropriate to distinguish between residential-type units and industrial, commercial, or institutional units.

The CAA allows EPA to divide source categories into subcategories based on differences in class, type, or size. 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. The design, operating, and emissions information that EPA has reviewed

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[3] Indirect-fired process heaters are combustion devices in which the combustion gases do not directly come into contact with process materials.

indicates differences in unit design that distinguish different types of boilers. Data indicate that there are significant design and operational differences between units that burn coal, biomass, liquid, and gaseous fuels.

Boiler systems are designed for specific fuel types and will encounter problems if a fuel with characteristics other than those originally specified is fired. While many boilers in the population data base are indicated to co-fire liquids or gases with solid fuels, in actuality most of these commonly use fuel oil or natural gas as a startup fuel only, and operate on solid fuel during the remainder of their operation. In contrast, some co-fired units are specifically designed to fire combinations of solids, liquids, and gases. Changes to the fuel type would generally require extensive changes to the fuel handling and feeding system (*e.g.,* a stoker using wood as fuel would need to be redesigned to handle fuel oil or gaseous fuel). 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 boiler or process heater. An additional effect of these changes would be extensive retrofitting needed to operate using a different fuel.

The design of the boiler or process heater, which is dependent in part on the type of fuel being burned, impacts the degree of combustion. Boilers and process heaters emit a number of different types of HAP emissions. Organic HAP are formed from incomplete combustion and are 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 formation of fuel-dependent HAP (metals, mercury, and acid gases) is dependent upon the composition of the fuel. These fuel-dependent 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. We concluded that the data were sufficient for determining that a distinguishable difference in performance exists based on unit design type. Therefore, because different types of units have different emission characteristics which may influence the feasibility of effectiveness of emission control, they should be regulated separately (*i.e.,* subcategorized). Accordingly, we propose to subcategorize boilers and process heaters based on unit design in order to account for these differences in emissions and applicable controls.

For the fuel-dependent HAP (metals, mercury, acid gases), we identified five basic unit types as subcategories. These are the following: (1) Units designed to burn coal, (2) units designed to burn biomass, (3) units designed to burn liquid fuel, (4) units designed to burn natural gas/refinery gas, and (5) units designed to burn other process gases. Within the basic unit types there are different designs and combustion systems that, while having a minor effect on fuel-related HAP emissions, have a much larger effect on organic HAP emissions. Therefore, we decided to further subcategorize based on these different unit designs but only in proposing standards for organic HAP emissions. We have identified the following 11 subcategories for organic HAP:

Pulverized coal units,
Stokers designed to burn coal,
Fluidized bed units designed to burn coal,
Stokers designed to burn biomass,
Fluidized bed units designed to burn biomass,
Suspension burners/Dutch Ovens designed to burn biomass,
Fuel Cells designed to burn biomass,
Units designed to burn liquid fuel,
Units designed to burn natural gas/refinery gas,
Units designed to burn other gases, and
Metal process furnaces.

These subcategories are based on the primary fuel that the boiler or process heater is designed to burn. We are aware that some boilers burn a combination of fuel types or burn a different fuel type as a backup fuel if the primary fuel supply is curtailed. However, boilers are designed based on the primary fuel type (and perhaps to burn a backup fuel) and can encounter operational problems if another fuel type that was not considered in its design is fired at more than 10 percent of the heat input to the boiler. Also, in some cases, a small amount of coal may be added to a biomass designed boiler to stabilize the combustion when the biomass has a higher moisture content than normal. In this case, it would not be appropriate to classify the boiler as being in one of the "coal" subcategories because the boiler design is such that it is constructed and operated to combust biomass, and could not combust primarily coal (without significant retrofitting or design changes). Therefore, we are proposing to define boilers and process heaters that burn at least 10 percent coal (on an annual heat input basis) as being in one of the coal subcategories. We are also proposing to define boilers and process heaters that burn at least 10 percent biomass, and less than 10 percent coal (on an annual heat input basis) as being in one of the biomass subcategories. We are proposing to define boilers and process heaters that burn at least 10 percent liquid fuel, and less than 10 percent solid fuel (on an annual heat input basis) as being in the liquid subcategory. We are proposing to define boilers and process heaters that burn at least 90 percent natural gas and/or refinery gas (on an annual heat input basis) as being in the Gas 1 subcategory. This would ensure that each boiler and process heater is subject to emissions standards calculated on the basis of the best performing units with similar design and operation. The remaining boilers and process heaters, except for those described below would be in the Gas 2 subcategory.

In addition, there is a certain class of natural gas-fired process heaters that are designed and operated differently compared to typical process heaters. A review of information gathered on process heaters used in the metal processing industries shows that these process heaters typically are designed with multiple burners that fire into individual combustion chambers. These individual burners are operated to cycle on and off to maintain the proper temperatures throughout the various zones of the process heater. Thus, due to their design, these process heaters rarely operate in a steady-state condition due to burners constantly starting up and shutting down. This results in emissions characteristics different from the process heaters used in other industries. The process heaters used in metal processing are natural gas-fired and include annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, and heat treat furnaces. Therefore, we propose to identify these metal processing process heaters (furnaces) as a separate eleventh subcategory.

In summary, we have identified 11 subcategories of boilers and process heaters located at major sources.[4]

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

This proposed rule includes numerical emission limits for PM, mercury, HCl, CO, and D/F. The selection of numerical emission limits as the format for this proposed rule

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[4] *See* Memorandum "Development of Baseline Emission Factors for Boilers and Process Heaters at Commercial, Industrial, and Institutional Facilities" located in the docket.

provides flexibility for the regulated community by allowing a regulated source to choose any control technology or technique to meet the emission limits, 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 limits as a mass of pollutant emitted per heat energy input to the boiler or process heater for the fuel-related HAP. The most typical units for the limits are pounds of pollutant emitted per million Btu of heat input. The mass per heat input units are consistent with other Federal and many State boiler regulations[5] and allows easy comparison between such requirements. Additionally, this proposed rule contains an option to monitor inlet chlorine and mercury content in the fuel to meet outlet emission rate limits. This option can only be done on a mass basis.

We are proposing outlet concentration as the format for the organic HAP. An outlet concentration limit for organic HAP would also be consistent with the format of other regulations.

Boilers and process heaters 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: Mercury, non-mercury metallic HAP, inorganic HAP, non-dioxin organic HAP, and D/F. The pollutants within each group have similar characteristics and can be controlled with the same techniques. For example, non-mercury metallic HAP can be controlled with PM controls. We chose to look at mercury 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. For the non-mercury metallic HAP, we chose to use PM as a surrogate. Most, if not all, non-mercury 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-mercury 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 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-mercury metals. Since non-mercury metallic HAP tend to be on small size particles (i.e., fine particle enrichment), we considered using $PM_{2.5}$ as the surrogate, but we determined that PM (filterable) was the more appropriate surrogate for two reasons. First, the test method (OTM 27) for measuring $PM_{2.5}$ is only applicable for use in exhaust stacks without entrained water droplets. Therefore, the test method (OTM 27) for measuring $PM_{2.5}$ is not applicable for units equipped with wet scrubbers which will likely be necessary to achieve the proposed HCl emission limits. Second, based on the emission data obtained during EPA's information collection effort from units not equipped with wet scrubbers, the majority of the filterable PM emitted from units that are well controlled for PM is fine particulate ($PM_{2.5}$). Thus, we are proposing to use PM (filterable), instead of $PM_{2.5}$, as the surrogate for non-mercury metals.

For non-metallic inorganic HAP, EPA is proposing using HCl as a surrogate. The emissions test information available to EPA indicate that the primary non-metallic inorganic HAP emitted from boilers and process heaters are acid gases, with HCl present in the largest amounts. Other inorganic compounds emitted are found in much smaller quantities. Control technologies that reduce HCl also control other inorganic compounds such as chlorine and other acid gases. Thus, the best controls for HCl would also be the best controls for other inorganic HAP that are acid gases. Therefore, HCl is a good surrogate for inorganic HAP because controlling HCl will result in control of other inorganic HAP emissions.

For organic HAP, we considered both THC and CO as a surrogate for non-dioxin organic HAP emitted from boilers and process heaters. CO has generally been used as a surrogate for organic HAP because CO is a good indicator of incomplete combustion and organic HAP are products of incomplete combustion. However, based on concerns that CO may not be an appropriate surrogate for D/F because, unlike other organic HAP, D/F can be formed outside the combustion unit, we are proposing to use CO as a surrogate for non-dioxin organic HAP. We are also proposing separate emission limits for D/F. For non-dioxin organic HAP, using CO as a surrogate is a reasonable approach because minimizing CO emissions will result in minimizing non-dioxin organic HAP. Methods used for the control of non-dioxin organic HAP emissions would be the same methods used to control CO emissions. These emission control methods include achieving good combustion or using an oxidation catalyst. Standards limiting emissions of CO will also result in decreases in non-dioxin organic HAP emissions (with the additional benefit of decreasing volatile organic compounds (VOC) emissions). Establishing emission limits for specific organic HAP (with the exception of D/F) would be impractical and costly. CO, which is less expensive to test for and monitor, is appropriate for use as a surrogate for non-dioxin organic HAP.

The Agency recognizes that the level and distribution of organic HAP associated with CO emissions will vary from unit to unit. For example, the principal organic HAP emitted from coal-fired units is benzene, which accounts for about 20 percent of the organic HAP while the principal organic HAP emitted from biomass-fired units is formaldehyde, which accounts for 34 percent of the organic HAP.[6] Limiting CO as a surrogate for only non-dioxin organic HAP will eliminate costs associated with speciating numerous compounds. The proposed standards establish separate emission limits for D/F because of the high toxicity associated with even low masses of these compounds.

THC could also be an appropriate surrogate for non-dioxin organic HAP because low THC also ensures good combustion efficiency and, thus, low organic HAP. However, we believe CO is preferable because many sources currently have CO CEMS. In addition, there are more CO emission data available for the various subcategories than THC emission data.

C. How did EPA determine the proposed emission limitations for existing units?

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, determined 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

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[5] For example, the new source performance standards for industrial, commercial, and institutional steam generating units (40 CFR subpart Db) have emission limits for sulfur dioxide, nitrogen oxide, and PM in terms of pounds per million Btu.

[6] Based on emission factors reported on EPA webpage "AP 42, Fifth Edition, Volume 1—Chapter 1: External Combustion Sources" located at *http://www.epa.gov/ttn/chief/ap42/ch01/index.html.*

sources for categories and subcategories with 30 or more sources or the best performing 5 sources for subcategories with less than 30 sources. This requirement constitutes the MACT floor for existing boilers and process heaters. 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 units?

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 from units within the subcategory from lowest emissions to highest emissions, and then taking the numerical average of the test results from the best performing (lowest emitting) 12 percent of sources.

We first considered whether fuel switching would be an appropriate control option for sources in each subcategory. We considered the feasibility of fuel switching to other fuels used in the subcategory and to fuels from other subcategories. This consideration included determining whether switching fuels would achieve lower HAP emissions. A second consideration was whether fuel switching could be technically achieved by boilers and process heaters in the subcategory considering the existing design of boilers and process heaters. We also considered the availability of various types of fuel.

After considering these factors, we determined that fuel switching was not an appropriate control technology for purposes of determining the MACT floor level of control for any subcategory. This decision was based on the overall effect of fuel switching on HAP emissions, technical and design considerations discussed previously in this preamble, and concerns about fuel availability.

Based on the emission factors reported in EPA's Technology Transfer Network, we determined that while fuel switching from solid fuels to gaseous or liquid fuels would decrease PM and some metals emissions, emissions of some organic HAP (*e.g.,* formaldehyde) would increase.[7] This determination is discussed in the memorandum "Development of Fuel Switching Costs and Emission Reductions for Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants" located in the docket.

A similar determination was made when considering fuel switching to cleaner fuels within a subcategory. For example, the term "clean coal" refers to coal that is lower in sulfur content and not necessarily lower in HAP content. Data gathered by EPA also indicates that within specific coal types HAP content can vary significantly. Switching to a low sulfur coal may actually increase emissions of some HAP. Therefore, it is not appropriate for EPA to include fuel switching to a low sulfur coal as part of the MACT standards for boilers and process heaters. Fuel switching from coal to biomass would result in similar impacts on HAP emissions. While this would reduce metallic HAP emissions, it would likely increase emissions of organics based on information in the emissions database.

Another factor considered was the availability of alternative fuel types. Natural gas pipelines are not available in all regions of the U.S., and natural gas is simply not available as a fuel for many industrial, commercial, and institutional boilers and process heaters. Moreover, even where pipelines provide access to natural gas, supplies of natural gas may not be adequate. For example, it is common practice in cities during winter months (or periods of peak demand) to prioritize natural gas usage for residential areas before industrial usage. Requiring boilers and process heaters to switch to natural gas would place an even greater strain on natural gas resources. Consequently, even where pipelines exist, some units would not be able to run at normal or full capacity during these times if shortages were to occur. Therefore, under any circumstances, there would be some units that could not comply with a requirement to switch to natural gas.

Similar problems for fuel switching to biomass could arise. Existing sources burning biomass generally are combusting a recovered material from the manufacturing or agriculture process. Industrial, commercial, and institutional facilities that are not associated with the wood products industry or agriculture may not have access to a sufficient supply of biomass materials to replace their fossil fuel.

As discussed previously in this preamble, there is a significant concern that switching fuels would be infeasible for sources designed and operated to burn specific fuel types. Changes in the type of fuel burned by a boiler or process heater (solid, liquid, or gas) may require extensive changes to the fuel handling and feeding system (*e.g.,* a stoker using wood as fuel would need to be redesigned to handle fuel oil or gaseous fuel). Additionally, burners and combustion chamber designs are generally not capable of handling different fuel types, and generally cannot accommodate increases or decreases in the fuel volume. Design changes to allow different fuel use, in some cases, may reduce the capacity and efficiency of the boiler or process heater. Reduced efficiency may result in less complete combustion and, thus, an increase in organic HAP emissions. For the reasons discussed above, we decided that fuel switching to cleaner solid fuels or to liquid or gaseous fuels is not an appropriate criteria for identifying the MACT floor emission levels for units in the boilers and process heaters category.

Therefore, the MACT floor limits for each of the HAP and HAP surrogates (PM, mercury, CO, HCl, and D/F) are calculated based on the performance of the lowest emitting (best performing) sources in each of the subcategories. We ranked all of the sources for which we had data based on their emissions and identified the lowest emitting 12 percent of the sources for each HAP.

We used the emissions data for those best performing affected sources to determine the emission limits to be proposed, with an accounting for variability. EPA must exercise its judgment, based on an evaluation of the relevant factors and 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 of Appeals has recognized that EPA may consider variability in estimating the degree of emission reduction achieved by best-performing sources and 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 level that best-performing source can expect to meet "every day and under all operating conditions").

In determining the MACT floor limits, we first determine the floor, which is the level achieved in practice by the average of the top 12 percent. We then assess variability of the best performers by using a statistical formula designed to estimate a MACT floor level that is achievable by the average of the best performing sources if the best performing sources were able to replicate the compliance tests in our

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[7] *See* EPA webpage "AP 42, Fifth Edition, Volume 1—Chapter 1: External Combustion Sources" located at *http://www.epa.gov/ttn/chief/ap42/ch01/index.html.*

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) in accounting for variability. A prediction interval for a future observation is an interval that will, with a specified degree of confidence, contain the next (or some other pre-specified) randomly selected observation from a population. In other words, the prediction interval estimates what 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 3 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% 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 sample standard deviation, which are two statistical measures calculated from the sample data. The average is the central value of a data set, and the standard deviation is the 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. To evaluate 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 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) is given by SES = SQRT(6/N) where N is the sample size. According to the small sample skewness hypothesis test, if the skewness statistic (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 relatively peaked (flat) distribution. Further, the standard error of the kurtosis statistic (SEK) is given by SEK = SQRT(24/N) where N is the sample size. According to the small sample kurtosis hypothesis test, if the kurtosis statistic (K) is greater than two times the SEK, the data distribution is typically considered to be non-normal.

We applied the skewness and kurtosis hypothesis tests to both the reported test values and the lognormal values of the reported test values. If the skewness (S) and kurtosis (K) statistics of the reported data set were both less than twice the SES and SEK, respectively, the dataset was classified as normally distributed. If neither of the skewness (S) and kurtosis (K) statistics, or only one of these statistics were less than twice the SES or SEK, respectively, then the skewness and kurtosis hypothesis tests were 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 both the reported values and the natural-log transformed reported values had skewness (S) and kurtosis (K) statistics that were greater than twice the SES or SEK, respectively, the normally distributed dataset was selected as the basis of the floor to be conservative. If the results of the skewness and kurtosis hypothesis tests were mixed for the reported values and the natural log-transformed reported values, we also 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.

Since the compliance with the MACT floor emission limit is based on the average of a three run test, the UPL is calculated by:

$$UPL = \overline{x} + t(0.99, n-1) \times \sqrt{s^2 \times \left(\frac{1}{n} + \frac{1}{m}\right)}$$

Where:

n = the number of test runs

m = the number of test runs in the compliance average

This calculation was performed using the following two Excel functions:

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)+(⅓))], for a one-tailed t-value (with 2 × probability), probability of 0.01, and sample size of n

Lognormal distribution: 99% UPL = EXP{AVERAGE(Natural Log Values of Test Runs in Top 12%) + [STDEV(Natural Log Values of Test Runs in Top 12%) × TINV(2 × probability, n-1 degrees of freedom)* SQRT((1/n)+(⅓))]}, for a one-tailed t-value (with 2 × probability), probability of 0.01, and sample size of n

Test method measurement imprecision can also be a component of data variability. At very low emissions levels as encountered in the data used to support this 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 rule, we specified the criteria for determining test-specific method detection levels. Those criteria insure that there is about a 1 percent probability of an error in deciding that the pollutant measured at the method detection level 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 method detection level. Because of matrix effects, laboratory techniques, sample size, and other factors, method detection levels normally vary from test to test. We requested sources to identify (i.e., flag) data which were measured below the method detection level and to report those values as equal to the test-specific method detection level.

Variability of data due to measurement imprecision is inherently and reasonably addressed in calculating the floor emissions limit when the data base represents multiple tests for which all of the data are measured significantly above the method detection level. That is less true when the data base includes emissions occurring below method detection capabilities and are reported as the method detection level values. The data base is then truncated at the lower end of the measurement range (i.e., no values reported below the method detection level) and we believe that a floor emissions limit based on a truncated data base or otherwise including values at or near the method detection level may not adequately account for data measurement variability. We did not adjust the calculated floor for the data used for this proposal; although, we believe that accounting for measurement imprecision should be an important consideration in calculating the floor emissions limit. 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 method detection level.

As noted above, the confidence level that a value measured at the detection level is greater than zero is about 99 percent. The expected measurement imprecision for an emissions value occurring at or near the method detection level 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 method detection level.[8] One approach that we believe could be applied to account for measurement variability would require defining a method detection level that is representative of the data used in establishing the floor emissions limits and also minimizes the influence of an outlier test-specific method detection level value. The first step in this approach would be to identify the highest test-specific method detection level 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 method detection level (*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 method detection level and compare it to the calculated floor emissions limit. If three times the representative method detection level 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 method detection level 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 method detection level in place of the calculated floor emissions limit to ensure that the floor emissions limit accounts for measurement variability. We request comment on this approach.

We are requesting comment on whether there is a more appropriate statistical approach to account for variability in the MACT floor analyses when there are emission data from a limited number of units in the subcategory.

However, after review of the available HAP data, including both emission test data and fuel analyses, we determined that it was inappropriate to use only this MACT floor approach to determine variability and to establish emission limits for boilers and process heaters, because this approach considers only the emissions test data. The main problem with using only the HAP emissions test data is that the data, which may reflect the variability of fuel-related HAP of the best performing units, may not reflect the variability of fuel-related HAP from the best performing units over the long term. Based on fuel-related HAP concentrations (nine individual samples collected over a 30-day period) obtained, pursuant to letters mandating data gathering issued under the authority of CAA section 114, fuel-related HAP levels in the various fuels can vary significantly over time.

The first step in establishing a MACT standard is to determine the MACT floor. A necessary step in doing so is determining the amount of HAP emitted. In the case of fuel-related HAP emitted, this is not necessarily a straightforward undertaking. Single stack measurements represent a snapshot in time of a source's emissions, always raising questions of how representative such emissions are of the source's emissions over time. The variations in fuel-related HAP inputs directly translate to a variability of fuel-related HAP stack emissions.

We believe that single short term stack test data (typically a few hours) are probably not indicative of long term emissions performance, and so are not the best indicators of performance over time. With these facts in mind, we carefully considered alternatives other than use of only single short-term stack test results to quantify performance for fuel-related HAP. We decided that the most accurate method available to us to determine long term fuel-related HAP emissions performance was to use data on the fuel-related HAP inputs in the fuels used by the best performing units, obtained as part of our information collection effort under the authority of CAA section 114, on long-term fuel-related HAP concentrations (nine individual samples collected over a 30-day period) in each fuel, along with the fuel-related HAP concentrations during the stack tests.

As previously discussed above, 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. Here, for example, we know that the HAP emission data from the best performing units are 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 would potentially exceed the floor emission levels a significant part of the time which would mean that variability was not properly taken into account. This variability includes the day-to-day variability in the total fuel-related HAP input to each unit and variability of the sampling and analysis methods, and it includes the variability resulting from site-to-site differences for the best performing units. We calculated the MACT floor based on the UPL (upper 99th percentile) as described earlier from the average performance of the best performing units, Students t-factor, and the variability of the best performing units.

This approach reasonably ensures that the emission limit selected as the MACT floor adequately represents the level of emissions actually achieved by the average of the units in the top 12 percent, considering ordinary 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 memorandum "MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source" in the docket.

1. Determination of MACT for the Fuel-Related HAP

In developing the proposed MACT floor for the fuel-related HAP (non-mercury metals, acid gases, and mercury), as described earlier, we are using PM as a surrogate for non-mercury metallic HAP and HCl as a surrogate for the acid gases. Table 2 of this preamble presents the number of units in each of the five subcategories, along with the

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[8] American Society of Mechanical Engineers, *Reference Method Accuracy and Precision (ReMAP): Phase 1, Precision of Manual Stack Emission Measurements,* CRTD Vol. 60, February 2001.

number of units from which we have collected emission data. Table 2 also presents for each subcategory and fuel-related HAP the number of units comprising the best performing units (top 12 percent), the average emission level of the top 12 percent, and the MACT floor (99 percent UPL of top 12 percent) which includes the variability across the best performing units and the long term variability across those units.

TABLE 2—SUMMARY OF MACT FLOOR RESULTS FOR THE FUEL-RELATED HAP FOR EXISTING SUBCATEGORIES

Subcategory	Parameter	PM	Mercury	HCl
Units designed for Coal firing	No. of sources in subcategory	578	578	578
	No. of sources with data	366	285	318
	No. in MACT floor	44	35	39
	Avg of top 12%, lb/MMBtu	7.24E–03	5.95E–07	4.23E–03
	99% UPL of top 12% (test runs), lb/MMBtu	0.0179	1.64E–06	7.38E–03
	99% UPL with fuel variability of top 12%, lb/MMBtu.	....	2.88E–06	1.11E–02
Units designed for Biomass firing	No. of sources in subcategory	420	420	420
	No. of sources with data	192	91	92
	No. in MACT floor	24	11	12
	Avg of top 12%, lb/MMBtu	6.06E–03	3.46E–07	4.34E–03
	99% UPL of top 12% (test runs), lb/MMBtu	0.0162	7.52E–07	6.00E–03
	99% UPL with fuel variability of top 12%, lb/MMBtu.	....	8.88E–07	....
Units designed for Liquid Fuel firing	No. of sources in subcategory	826	826	826
	No. of sources with data	91	177	190
	No. in MACT floor	11	22	23
	Avg of top 12%, lb/MMBtu	1.40E–03	1.91E–06	2.59E–04
	99% UPL of top 12% (test runs), lb/MMBtu	0.00323	2.78E–06	3.26E–04
	99% UPL with fuel variability of top 12%, lb/MMBtu.	....	3.97E–06	8.04E–04
Units designed for other gas firing	No. of sources in subcategory	199	199	199
	No. of sources with data	13	8	8
	No. in MACT floor	2	1	1
	Avg of top 12%, lb/MMBtu	0.011	8.25E–08	1.70E–06
	99% UPL of top 12% (test runs), lb/MMBtu	0.045	1.86E–07	2.50E–06

For three cases, the proposed new and existing source MACT floors are almost identical because the best performing 12 percent of existing units (for which we have emissions information) is only one or two sources. The reason we look to the best performing 12 percent of sources, even though we have data on fewer than 5 sources, is that these subcategories consist of 30 or more units. CAA section 112(d)(3)(A) provides that standards for existing sources shall not be less stringent than "the average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emissions information), * * * in the category or subcategory for categories and subcategories with 30 or more sources." A plain reading of the above statutory provisions is to apply the 12 percent rule in deriving the MACT floor for those categories or subcategories with 30 or more sources. The parenthetical "(for which the Administrator has emissions information)" in CAA section 112(d)(3)(A) modifies the best performing 12 percent of existing sources, which is the clause it immediately follows.

However, in cases where there are 30 or more sources but little emission data, this results in only a few units setting the existing source floor with the result that the new and existing source MACT floors are almost identical. In contrast, if these subcategories had less than 30 sources, we would be required to use the top five best performing sources, rather than the one or two that comprise the top 12 percent. Section 112(d)(3)(B).

We are seeking comment on whether, with the facts of this rulemaking, we should consider reading the intent of Congress to allow us to consider five sources rather than just one or two. First, it seems evident that Congress was concerned that floor determinations should reflect a minimum quantum of data: At least data from 5 sources for source categories of less than 30 sources (assuming that data from 5 sources exist). Second, it does not appear that this concern would be any less for subcategories with 30 or more sources. We are specifically requesting comment on this interpretation relating to the proposed MACT floors.[9]

2. Determination of MACT for Organic HAP

In developing the MACT floor for organic HAP, as described earlier, we are using CO as a surrogate for non-dioxin organic HAP. Table 3 of this preamble presents the number of units in each of the 11 subcategories, along with the number of units from which we have collected emission data. Table 3 also presents for each subcategory (for CO and D/F) the number of units comprising the best performing units (top 12 percent), the average emission level of the top 12 percent, and the MACT floor (99 percent UPL of top 12 percent) which includes the variability across the best performing units and the long term variability.

We calculated the MACT floors based on the upper 99th percentile UPL from the average performance of the best performing units and their variances as described earlier for the fuel-related HAP.

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[9] The impact of using a minimum of five sources in the MACT floor analyses for these subcategories and HAP are presented in the Memorandum "MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Sources" located in the Docket.

TABLE 3—SUMMARY OF MACT FLOOR RESULTS FOR THE ORGANIC HAP SUBCATEGORIES

Subcategory	Parameter	CO	Dioxin/Furan (TEQ)
Stoker—Coal	No. of sources in subcategory	361	361.
	No. of sources with data	61	14.
	No. in MACT floor	8	2.
	Avg of top 12%	21.4 ppm @ 3% O_2	0.00182 ng/dscm @ 7% O_2.
	99% UPL of top % (test runs)	48.8 ppm @ 3% O_2	0.00274 ng/dscm @ 7% O_2.
Fluidized Bed—Coal	No. of sources in subcategory	31	31.
	No. of sources with data	17	12.
	No. in MACT floor	3	2.
	Avg of top 12%	12.5 ppm @ 3% O_2	0.000471 ng/dscm @ 7% O_2.
	99% UPL of top % (test runs)	21.4 ppm @ 3% O_2	0.00168 ng/dscm @ 7% O_2.
PC—Coal	No. of sources in subcategory	186	186.
	No. of sources with data	41	10.
	No. in MACT floor	5	2.
	Avg of top 12%	19.2 ppm @ 3% O_2	0.00158 ng/dscm @ 7% O_2.
	99% UPL of top % (test runs)	82.8 ppm @ 3% O_2	0.00307 ng/dscm @ 7% O_2.
Stoker—Biomass	No. of sources in subcategory	320	320.
	No. of sources with data	119	16.
	No. in MACT floor	15	2.
	Avg of top 12%	203 ppm @ 3% O_2	0.000819 ng/dscm @ 7% O_2.
	99% UPL of top % (test runs)	551 ppm @ 3% O_2	0.00339 ng/dscm @ 7% O_2.
Fluidized Bed—Biomass	No. of sources in subcategory	12	12.
	No. of sources with data	7	6.
	No. in MACT floor	5	5.
	Avg of top 12%	97.1 ppm @ 3% O_2	0.00507 ng/dscm @ 7% O_2.
	99% UPL of top 12% (test runs)	245 ppm @ 3% O_2	0.0127 ng/dscm @ 7% O_2.
Suspension Burner/Dutch Oven.	No. of sources in subcategory	62	62.
	No. of sources with data	17	3.
	No. in MACT floor	3	1.
	Avg of top 12%	362 ppm @ 3% O_2	0.00952 ng/dscm @ 7% O_2.
	99% UPL of top 12% (test runs)	1010 ppm @ 3% O_2	0.0279 ng/dscm @ 7% O_2.
Fuel Cell—Biomass	No. of sources in subcategory	26	26.
	No. of sources with data	16	7.
	No. in MACT floor	5	5.
	Avg of top 12%	130 ppm @ 3% O_2	0.00552 ng/dscm @ 7% O_2.
	99% UPL of top 12% (test runs)	262 ppm @ 3% O_2	0.0148 ng/dscm @ 7% O_2.
Units designed for Liquid fuel firing.	No. of sources in subcategory	826	826.
	No. of sources with data	116	17.
	No. in MACT floor	14	3.
	Avg of top 12%	0.443 ppm @ 3% O_2	0.000733 ng/dscm @ 7% O_2.
	99% UPL of top 12% (test runs)	0.911 ppm @ 3% O_2	0.00182 ng/dscm @ 7% O_2.
Units designed for other gases firing.	No. of sources in subcategory	199	199.
	No. of sources with data	75	5.
	No. in MACT floor	9	1.
	Avg of top 12%	0.0737 ppm @ 3% O_2	0.00267 ng/dscm @ 7% O_2.
	99% UPL of top 12% (test runs)	0.134 ppm @ 3% O_2	0.00828 ng/dscm @ 7% O_2.

For organic HAP, as previously discussed above for fuel-related HAP, 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. Here, however, we know that the organic HAP emissions will also vary over the operating range of the unit, unlike fuel-related HAP emissions. Organic HAP are combustion-related pollutants. That is, their levels of emissions are a function of the combustion process. Combustion units operate most efficiently when operated at or near their design capacity. The combustion efficiency tends to decrease as the unit's load (steam production) decreases. Most industrial or commercial/institutional units do not continuously operate at or near their design capacity but operate according to the facility's demand for steam. Thus, operation at lower capacity rates must be accounted for in determining operational variability.

As part of EPA's information collection effort, we obtained data on organic HAP (THC and CO) from six units (two coal-fired, two biomass-fired, and two gas-fired) that were collected using CEM over a 30-day period. All of these units were selected to test using CEM to provide variability information because their stack test results indicated that they were among the best performing units.

The CEMS data shows that CO (as a surrogate for non-dioxin organic HAP) from best performing units did not vary much when such unit is operated at below design capacity. Therefore, even though ICI units, due to steam demand, may operate at these low load conditions, no additional variability due to operating load needs to be accounted for since the average CO emission levels that include these low load conditions are within the variability range determined by the statistical analyses of CO emissions from the best performing units. Thus, we are proposing to add no additional variability factor to account for load variability to the MACT floor 99 percent UPL values determined from the stack test data for CO emissions.

This approach reasonably ensures that the emission limit selected as the MACT floor adequately represents the average level of control actually achieved by units in the top 12 percent in each subcategory, considering ordinary operational variability of those units. Both the analysis of the measured emissions from units representative of the top 12 percent, and the variability analysis of those units, 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.

As was the case for the three fuel-dependent MACT floors, the proposed new and existing source MACT floors for eight combustion-dependent subcategories are almost identical because the best performing 12 percent of units (for which we have emissions information) is only one or two sources. Again, the reason we look to the best performing 12 percent of sources is that these subcategories consist of 30 or more units. In contrast, if these subcategories had less than 30 sources, we would be required to use the top five best performing sources, rather than the one or two that comprise the top 12 percent. As stated previously, we are seeking comment on whether, with the facts of this rulemaking, we should consider reading the intent of Congress to allow us to consider five sources rather than just one, two, or three. We are specifically requesting comment on this interpretation relating to the proposed MACT floors.

3. 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."

The standard reference methods for measuring emissions of mercury, CO (as a surrogate for organic HAP), D/F, HCl (as a surrogate for acid gases) and PM (as a surrogate for non-mercury metals) are EPA Methods 29, 10, 23, 26A and 5. These methods are reliable but relatively expensive as a group. However, the methods are generally not able to accurately sample small diameter (less than 12 inches) stacks. For example, in these small diameter stacks, the conventional EPA Method 5 stack assembly blocks a significant portion of the cross-section of the duct and, if unaccounted for, could cause inaccurate measurements. Many existing small boilers and process heaters have stacks with diameters less than 12 inches. The stack diameter is generally related to the size of the unit. Units that have capacity below 10 million Btu per hour generally have stacks with diameters less than 12 inches. Also, many existing small units do not currently have sampling ports or a platform for accessing the exhaust stack which would require an expensive modification to install sampling ports and a platform.

We conducted a cost analysis[10] to evaluate the economic impact of the testing and monitoring costs that facilities with small units would incur to demonstrate compliance with the proposed emission limits. The compliance costs imposed on each facility would not only include the costs of the stack tests and monitoring equipment but would also include the capital costs of any installed control equipment. We estimate that the total capital costs of installing control equipment on the over 7,400 small boilers and process heaters to achieve the proposed emission limits would be $6.3 billion. In addition to these costs, additional costs would be incurred because many of these small units do not have test ports or testing platforms installed in order to conduct performance testing. Prior to conducting a stack test each unit would need to construct or rent scaffolding and install test ports. EPA estimates that these small sources would incur an additional $185 million to install test ports and rent temporary scaffolding. Many establishments in each industry, commercial, or institutional sector are associated with multiple (as many as a 700) small units.

The results of the analysis indicate that the annual costs for testing and monitoring costs alone would have a significant adverse economic impact on these facilities. The severity of the economic impact would depend on the size of the facility.

Based on this analysis, the Administrator has determined under CAA section 112(h) that it is not feasible to enforce emission standards for a particular class of existing boilers and process heaters because of the technological and economic limitations described above. Thus, a work practice, as discussed below, is being proposed to limit the emission of HAP for existing boilers and process heaters having a heat input capacity of less than 10 million Btu per hour. We are specifically requesting comment on whether a threshold higher than 10 million Btu per hour meets the technical and economic limitations as specified in CAA section 112(h).

For existing units, the only work practice being used that potentially controls HAP emissions is a tune-up. Fuel dependent HAP are typically controlled by removing them from the flue gas after combustion. The only work practices expected to minimize fuel dependent HAP emissions are reducing the fuel usage or fuel switching to a fuel type with a lower HAP content. Fuel usage can be reduced by improving the combustion efficiency of the unit, such as, by a tune-up. As combustion efficiency decreases, fuel usage must increase to maintain

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[10] *Memorandum:* Methodology for Estimating Impacts from Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources of Hazardous Air Pollutant Emissions, March 23, 2010.

constant energy output. This increased fuel use results in increased emissions.

On the other hand, 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 oxygen requires temperature (high enough to ignite the fuel constituents), mixing or turbulence (to provide intimate oxygen-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 organic HAP emissions.

We have obtained information on units that reported using GCP, as part of the information collection effort for the NESHAP. The data that we have suggests that units typically conduct tune-ups. We also reviewed State regulations and permits. The work practices listed in State regulations includes tune-ups (10 States), operator training (1 State), periodic inspections (2 States), and operation in accordance with manufacturer specifications (1 State). Of the units with a capacity of less than 10 MMBtu/h that responded to EPA's information collection effort for the NESHAP, 80 percent reported conducting a tune-up program. Ultimately, we determine that at least 6 percent of the units in each of the subcategories are subject to a tune-up requirement. Therefore, the proposed work practice of a tune-up[11] program does establish the MACT floor for HAP emissions from existing units with a heat input capacity of less than 10 MMBtu/h.

We are also proposing a work practice standard under section 112(h) that would require an annual tune-up for existing boilers and process heaters combusting natural gas or refinery gas. These boilers and process heaters are units included in the Gas 1 and metal processing furnace subcategories. We are specifically seeking comment on whether the application of measurement methodology to sources in this subcategory is impracticable due to technological or economic limitations, as specified in section 112(h)(2)(B).

This work practice standard is being proposed for several reasons. First, the capital costs estimated for installing controls on these boilers and process heaters to comply with MACT limits for the five HAP groups is over $14 billion. This cost includes installation of a combination system of a fabric filter (for PM, mercury, and D/F control) and a wet scrubber (for HCl control). This capital cost is higher than the estimated combined capital cost for boilers and process heaters in all of the other subcategories. The projected control system needed for boilers and process heaters in the other subcategories is also a combined fabric filter/wet scrubber system.

Second, we believe that proposing emission standards for gas-fired boilers and process heaters that result in the need to employ the same emission control system as needed for the other fuel types would have the negative benefit of providing a disincentive for switching to gas as a control technique (and a pollution prevention technique) for boilers and process heaters in the other fuel subcategories. In addition, emission limits on gas-fired boilers and process heaters may have the negative benefit of providing an incentive for a facility to switch from gas (considered a "clean" fuel) to a "dirtier" but cheaper fuel (i.e., coal). It would be inconsistent with the emissions reductions goals of the CAA, and of section 112 in particular, to adopt requirements that would result in an overall increase in HAP emissions. We are soliciting comment on the extent to which natural gas facilities would be expected to switch to a "dirtier" fuel if emissions limits for such facilities are adopted.

Thus, a work practice, as discussed above for small boilers and process heaters, is being proposed to limit the emission of HAP for existing natural gas-fired and refinery gas-fired boilers and process heaters.

We request comments on whether the emission limits listed in Table 4 of this preamble for the Gas 1 and Metal Process Furnace subcategories should be promulgated. Comments should include detailed information regarding why emission limits for these gas-fired boilers and process heaters are appropriate.

TABLE 4—SUMMARY OF MACT FLOOR RESULTS FOR THE GAS 1 AND METAL PROCESS FURNACE SUBCATEGORIES

Subcategory	Parameter	PM	Mercury	HCl	CO	Dioxin/furan (total TEQ)
Units designed for NG/RG firing.	No. of sources in subcategory.	10,783	10,783	10,783	10,783	10,783.
	No. of sources with data.	144	14	11	754	8.
	No. in MACT floor	18	2	2	91	1.
	Avg of top 12%	0.00388 lb/MMBtu	1.1E–07 lb/MMBtu	1.01E–04 lb/MMBtu.	1.45 ppm @ 3% oxygen.	0.0026 ng/dscm @ 7% oxygen.
	99% UPL of top 12% (test runs).	0.03 lb/MMBtu	2.0E–07 lb/MMBtu	0.0002 lb/MMBtu	20 ppm @ 3% oxygen.	0.01 ng/dscm @ 7% oxygen.
Metal Process Furnaces.	No. of sources in subcategory.	749	749	749	749	749.
	No. of sources with data.	9	7	9	15	7.
	No. in MACT floor	2	1	2	2	1.
	Avg of top 12%	0.0047 lb/MMBtu	3.3E–08 lb/MMBtu	1.92E–04 lb/MMBtu.	0.38 ppm @ 3% oxygen.	0.0026 ng/dscm @ 7% oxygen.
	99% UPL of top 12% (test runs).	0.02 lb/MMBtu	2.0E–07 lb/MMBtu	0.0004 lb/MMBtu	2 ppm @ 3% oxygen.	0.004 ng/dscm @ 7% oxygen.

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[11] Tune-up procedure is specified in section 63.7540 of this proposed rule and includes making adjustments to the burner to optimize the flame to minimize CO emissions consistent with the manufacturer's specifications.

E. How did EPA consider beyond-the-floor options for existing units?

Once the MACT floor determinations were done 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. A detailed description of the beyond-the-floor consideration is in the memorandum "Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants" in the docket.

We could not identify better HAP emissions reduction approaches that could achieve greater emissions reductions of HAP than the control technology combination (fabric filter, carbon injection, scrubber, and GCP) that we expect will be used to meet the MACT floor level of control.

For each subcategory, 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, and supplies to industrial customers can be limited during periods when natural gas demand exceeds supply. Additionally, the estimated emissions reductions that would be achieved if solid and liquid fuel units switched to natural gas were compared with the estimated cost of converting existing solid fuel and liquid fuel units to fire natural gas. The annualized cost of fuel switching was estimated to be $13.5 billion compared with $3.5 billion under the floor approach. The emission reduction associated with fuel switching was estimated to be 4,296 tons per year for metallic HAP, 8 tons per year for mercury, and 50,332 tons per year for inorganic HAP (HCl and HF). The cost for fuel switching is over double the cost of the floor approach while the emission reductions associated with fuel switching are approximately the same. Additional detail on the calculation procedures is provided in the memorandum "Development (2010) of Fuel Switching Costs and Emissions Reductions for Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants" in the docket.

We also considered the pollution prevention and energy conservation measure of an energy assessment/audit as a beyond-the-floor option for HAP emissions. An energy assessment provides valuable information on improving energy efficiency. An energy assessment, or audit, is an in-depth energy study identifying all energy conservation measures appropriate for a facility given its operating parameters. An energy assessment refers to a process which involves a thorough examination of potential savings from energy efficiency improvements, pollution prevention, and productivity improvement. It leads to the reduction of emissions of pollutants through process changes and other efficiency modifications. Besides reducing operating and maintenance costs, improving energy efficiency reduces negative impacts on the environment and results in reduced emissions and improved public health. Improvement in energy efficiency results in decreased fuel use which results in a corresponding decrease in emissions (both HAP and non-HAP) from the combustion unit, but not necessarily a decrease in emissions of all HAP emitted. The Department of Energy has conducted energy assessments at selected manufacturing facilities and reports that facilities can reduce fuel/energy use by 10 to 15 percent by using best practices to increase their energy efficiency. Many best practices are considered pollution prevention because they reduce the amount of fuel combusted which results in a corresponding reduction in emissions from the fuel combustion. The most common best practice is simply tuning the boiler to the manufacturer's specification.

The one-time cost of an energy assessment ranges from $2500 to $55,000 depending on the size of the facility. The total annualized cost if each major source facility conducted an energy assessment is estimated at $26 million. If a facility implemented the cost-effective energy conservation measures identified in the energy assessment, it would potentially result in greater HAP reduction than achieved by a boiler tune-up alone and potentially reducing HAP emissions (HCl, mercury, non-mercury metals, and VOC) by an additional 820 to 1,640 tons per year. In addition, the costs of any energy conservation improvement will be offset by the cost savings in lower fuel costs. Therefore, we decided to go beyond the MACT floor for this proposed rule for the existing units. These proposed standards for existing units include the requirement of a performance of an energy assessment to identify cost-effective energy conservation measures. Since there was insufficient information to determine if requiring implementation of cost-effective measures were economically feasible, we are seeking comment on this point.

In this proposed rule, we are defining a cost-effective energy conservation measure to be any measure that has a payback (return of investment) period of 2 years or less. This payback period was selected based on section 325(o)(2)(B)(iii) of the Energy Policy and Conservation Act which states that there is a presumption that an energy conservation standard is economically justified if the increased installed cost for a measure is less than three times the value of the first-year energy savings resulting from the measure.

We believe that an energy assessment is an appropriate beyond-the-floor control technology because it is one of the measures identified in CAA section 112(d)(2). CAA section 112(d)(2) states that "Emission standards promulgated * * * and applicable to new or existing sources * * * is achievable * * * through application of measures, processes, methods, systems or techniques including, but not limited to measures which * * * reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications * * *"

The purpose of an energy assessment is to identify energy conservation measures (such as, process changes or other modifications to the facility) that can be implemented to reduce the facility energy demand which would result in reduced fuel use. Reduced fuel use will result in a corresponding reduction in HAP, and non-HAP, emissions. Thus, an energy assessment, in combination with the MACT emission limits will result in the maximum degree of reduction in emissions as required by 112(d)(2). Therefore, we are proposing to require all existing sources to conduct a one-time energy assessment to identify cost-effective energy conservation measures.

We are proposing that the energy assessment be conducted by energy professionals and/or engineers that have expertise that cover all energy using systems, processes, and equipment. We are aware of, at least, two organizations that provide certification of specialists in evaluating energy systems. We are proposing that a qualified specialized is someone who has successfully completed the Department of Energy's Qualified Specialist Program for all systems or a professional engineer certified as a Certified Energy Manager by the Association of Energy Engineers.

As part of the energy assessment, we are proposing that the facility assess its energy management program and practices using EPA's ENERGY STAR Facility Energy Management Assessment Matrix. ENERGY STAR has a simple facility energy management assessment tool that can be used as part of the assessment process. This tool identifies gaps in current practices. Facilities, as part of the requirement, would identify steps to close the management gaps. We are also proposing that the facility develop an energy management program according to the ENERGY STAR Guidelines for Energy Management (*see www.energystar.gov/guidelines*).[12]

We are specifically requesting comment on: (1) Whether our estimates of the assessment costs are correct; (2) is there adequate access to certified assessors; (3) are there other organizations for certifying energy engineers; (4) are online tools adequate to inform the facility's decision to make efficiency upgrades; (5) is the definition of "cost-effective" appropriate in this context since it refers to payback of energy saving investments without regard to the impact on HAP reduction; (6) what rate of return should be used; and (7) are there other guidelines for energy management beside ENERGY STAR's that would be appropriate.

We considered proposing a beyond-the-floor requirement for certain sources in the natural gas and refinery gas subcategory (i.e., the Gas 1 subcategory). Specifically, we considered proposing that facilities with boilers or process heaters combusting refinery gas install and maintain a carbon adsorber bed system [13] to remove mercury from the refinery gas before combustion in a boiler or process heater. Based on data from the information collection effort, refinery gas contains mercury and additional mercury reductions can be achieved from units combusting refinery gas. Consequently, we analyzed the mercury emissions reductions and additional cost of adopting this work practice. The annualized cost of the carbon adsorber bed system to treat the refinery gas prior to combustion is estimated to be about 1.6 billion dollars with a mercury emission reduction of 0.8 tons. The results indicated that while additional mercury emissions reductions would be realized, the costs would be too high to consider it a feasible beyond-the-floor option. Nonair quality health, environmental impacts, and energy effects were not significant factors, because there would be little difference in the nonair quality health and environmental impacts of requiring the installation of carbon bed adsorbers. Therefore, we are not proposing installation of a carbon adsorber bed system as a beyond-the-floor requirement.

F. Should EPA consider different subcategories for solid fuel boilers and process heaters?

The boilers and process heaters source category is tremendously heterogeneous. 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 or adequate data submitted with the comment), how EPA should define any additional/different subcategories, how EPA should account for varied or changing fuel mixtures, and how EPA should use the available data to determine the MACT floor for any new or different categories.

G. How did EPA determine the proposed emission limitations for new units?

All standards established pursuant to section 112 of the CAA 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 boilers and process heaters 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 units?

Similar to the MACT floor process used for existing units, 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 emission test results from units within the subcategory from lowest to highest to identify the best controlled similar source. The MACT floor limits for each of the HAP and HAP surrogates (PM, mercury, CO, HCl, and D/F) 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 limits for new sources were calculated using the same formula as was used for existing sources. However, as was the case for the existing MACT floor analysis, we determined that it was inappropriate to use only this MACT floor approach to determine variability and to establish emission limits for new boilers and process heaters. The main problem with using only the HAP emissions test data is that the data may not reflect the variability of fuel-related HAP from the best controlled similar source over the long term. Based on our current information, fuel-related HAP levels in the various fuels can vary significantly over time. The variations in fuel-related HAP inputs directly translate to a variability of fuel-related HAP stack emissions.

As previously discussed above, 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. If we do not account for this variability, we would expect that even the best controlled similar source would potentially exceed the floor emission levels a significant part of the time which would mean that their variability was not properly accounted for when setting the floor. 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, Students t-factor, and the total variability of the best-controlled source.

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[12] The location of the guidance is: *http://www.energystar.gov/index.cfm?c=guidelines.assess_facility_energy.*

[13] Carbon adsorption of mercury can be accomplished by (a) injecting dry carbon with or without other dry sorbents into the offgas upstream of a PM control device (typically a baghouse), or (b) using a fixed or moving bed of granular carbon through which the offgas flows. In a typical fixed bed carbon adsorption system, the flue gas flows through a vessel packed with a specified depth of the carbon granules. The bed and packing are designed to limit the linear velocity of the offgas in the bed to increase the contact time with the carbon. Due to the increased contact times and typically lower operating temperatures, better removal efficiencies can be achieved than for carbon injection. At a residence time of 10 seconds in the carbon bed, virtually all of the mercury can be removed. (Ref. NUCON INTERNATIONAL, Inc., "Design & Performance Characteristics of MERSORBB Mercury Adsorbents in Liquids and Gases," NUCON 11B28, August 1995.)

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 memorandum "MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants" 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. While 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 source. Thus, for existing units, we are concerned about estimating the central tendency of a set of multiple units, while 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 unit analysis must account for variability. To accomplish this for new sources, for the fuel dependent HAP emissions, we determined what the best controlled source has achieved in light of the inherent and unavoidable variations in the HAP content of the fuel that such unit might potentially use. For non-fuel dependent HAP emissions, on the other hand, we look at the inherent variability of the control technology used by the best-controlled source in the subcategory. These approaches, respectively, represent the most reasonable way to estimate performance for purposes of establishing MACT floors for new units, given the data available.

For fuel dependent HAP emissions (mercury and HCl), we calculated the variability factor by looking at data on HAP variability in fuel obtained through our information collection request. We derived the fuel dependent variability factor by dividing the highest observed HAP concentration by the lowest observed HAP concentration from the fuel analyses from the best-controlled source. Once we calculated the fuel dependent variability factors, we applied these factors to the average measured emissions performance of the best controlled similar source to derive the MACT floor level of control. This approach reasonably estimates the best source's level of emissions, adjusted for unavoidable variation in fuel characteristics which have a direct impact on emissions.

1. Determination of MACT for the Fuel-Related HAP

In developing the MACT floor for the fuel-related HAP (PM, HCl, and mercury), as described earlier, we are using PM as a surrogate for non-mercury metallic HAP and HCl as a surrogate for the acid gases. Table 5 presents for each subcategory and fuel-related HAP the average emission level of the best controlled similar source and the MACT floor (99 percent UPL) which includes the variability across the best controlled similar source and the long term variability of that source.

TABLE 5—SUMMARY OF MACT FLOOR RESULTS FOR THE FUEL-RELATED HAP FOR NEW SOURCES

Subcategory	Parameter	PM Lb/MMBtu	Mercury Lb/MMBtu	HCl Lb/MMBtu
Units designed for Coal firing	Avg of top performer	0.000396	1.18E–07	3.85E–05
	99% UPL of top performer (test runs)	0.000928	3.89E–07	5.21E–05
Units designed for Biomass firing	Avg of top performer	0.00216	9.73E–08	7.85E–04
	99% UPL of top performer (test runs)	0.00711	1.86E–07	3.07E–03
Units designed for Liquid Fuel firing	Avg of top performer	0.000511	5.87E–08	3.99E–04
	99% UPL of top performer (test runs)	0.00154	2.47E–07	9.80E–04
Units designed for other gas firing	Avg of top performer	0.00042	8.25E–08	1.70E–06
	99% UPL of top performer (test runs)	0.0024	1.86E–07	2.50E–06

2. Determination of MACT for Organic HAP

In developing the MACT floor for organic HAP, as described earlier, we are using CO as a surrogate for non-dioxin organic HAP. Table 6 presents for each subcategory and CO and D/F the average emission level of the best controlled similar source and the MACT floor (99 percent UPL) which includes the variability across the best controlled similar source and the long term variability of that source.

TABLE 6—SUMMARY OF MACT FLOOR RESULTS FOR THE ORGANIC HAP FOR NEW SOURCES

Subcategory	Parameter	CO (ppm @ 3 percent oxygen)	Dioxin/Furan (TEQ) (ng/dscm @ 7 percent oxygen)
Stoker—Coal	Avg of top performer	4.29	1.52E–03
	99% UPL of top performer (test runs)	6.53	2.82E–03
Fluidized Bed—Coal	Avg of top performer	8.26	9.05E–06
	99% UPL of top performer (test runs)	*39.9	2.54E–05
PC—Coal	Avg of top performer	25.0	1.04E–03
	99% UPL of top performer (test runs)	*97.5	1.47E–03
Stoker—Biomass	Avg of top performer	920	1.52E–05
	99% UPL of top performer (test runs)	*3730	4.86E–05
Fluidized Bed—Biomass	Avg of top performer	25.8	2.27E–03
	99% UPL of top performer (test runs)	34.2	6.48E–03
Suspension Burner/Dutch Oven.	Avg of top performer	352	9.52E–03
	99% UPL of top performer (test runs)	*1050	2.79E–02
Fuel Cell—Biomass	Avg of top performer	110	2.42E–04

TABLE 6—SUMMARY OF MACT FLOOR RESULTS FOR THE ORGANIC HAP FOR NEW SOURCES—Continued

Subcategory	Parameter	CO (ppm @ 3 percent oxygen)	Dioxin/Furan (TEQ) (ng/dscm @ 7 percent oxygen)
	99% UPL of top performer (test runs)	*264	4.17E–04
Units designed for Liquid fuel firing	Avg of top performer	0.125	1.09E–03
	99% UPL of top performer (test runs)	0.125	1.52E–03
Units designed for other gases firing	Avg of top performer	0.0129	2.67E–03
	99% UPL of top performer (test runs)	0.0129	8.28E–03

* Value is higher than existing floor limit in the same subcategory. Therefore defaulted to existing floor limit for the same subcategory.

For organic HAP, as previously discussed above for the fuel-related, 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. Here, we know that CO (as a surrogate for non-dioxin organic HAP) emissions does not vary significantly over the operating range of the unit. Thus, we have not added any additional operational variability to account for operation at lower capacity rates.

We are proposing a work practice standard under section 112(h) that would require an annual tune-up for new boilers and process heaters combusting natural gas or refinery gas. These boilers and process heaters are units included in the Gas 1 and metal processing furnace subcategories. We are specifically seeking comment on whether the application of measurement methodology to sources in this subcategory is impracticable due to technological or economic limitations, as specified in section 112(h)(2)(B).

This proposal for new boilers and process heaters combusting natural gas or refinery gas is based on the same reasons discussed previously for existing boilers and process heaters combusting natural gas or refinery gas. That is, we believe that proposing emission standards for new gas-fired boilers and process heaters that result in the need to employ the same emission control system as needed for the other fuel types would have the negative benefit of providing a disincentive for switching to gas as a control technique (and a pollution prevention technique) for boilers and process heaters in the other fuel subcategories. In addition, emission limits on gas-fired boilers and process heaters may have the negative benefit of providing an incentive for a facility to switch from gas (considered a "clean" fuel) to a "dirtier" but cheaper fuel (*i.e.,* coal). It would be inconsistent with the emissions reductions goals of the CAA, and of section 112 in particular, to adopt requirements that would result in an overall increase in HAP emissions. We are soliciting comment on the extent to which new facilities would be expected to switch away from natural gas to a "dirtier" fuel if emissions limits for new such facilities are adopted.

Thus, a work practice, as discussed above for existing boilers and process heaters combusting natural gas or refinery gas, is being proposed to limit the emission of HAP for new natural gas-fired and refinery gas-fired boilers and process heaters.

We request comments on whether the emission limits listed in Table 7 of this preamble for new units in the Gas 1 and Metal Process Furnace subcategories should be promulgated. Comments should include detailed information regarding why emission limits for these gas-fired boilers and process heaters are appropriate.

TABLE 7—SUMMARY OF MACT FLOOR RESULTS FOR NEW UNITS IN THE GAS 1 AND METAL PROCESS FURNACE SUBCATEGORIES

Subcategory	Parameter	PM Lb/MMBtu	Mercury Lb/MMBtu	HCl LB/MMBtu	CO (ppm @ 3 percent oxygen)	Dioxin/Furan (Total TEQ) (ng/dscm @ 7 percent oxygen)
Units designed for NG/RG firing.	Avg of top performer	0.00013	9.4E–08	7.3E–05	5	0.0026
	99% UPL of top (test runs) =	0.0005	2.0E–07	0.0002	20	0.01
Metal Process Furnaces	Avg of top performer	0.0065	3.3E–08	8.6E–05	0.5	0.0026
	99% UPL of top (test runs) =	0.02	2.0E–07	0.0002	2	0.004

I. How did EPA consider beyond-the-floor for new units?

The MACT floor level of control for new units 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.

Fuel switching to natural gas is a potential regulatory option beyond the new source floor level of control that would reduce HAP emissions from non-gas-fired units. However, based on current trends within the industry, EPA projects that the majority of new boilers and process heaters will be built to fire natural gas as opposed to solid and liquid fuels such that the overall emissions reductions associated with this option would be minimal. In addition, natural gas supplies are not available in some areas, and supplies to industrial customers can be limited during periods when natural gas demand exceeds supply. 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.[14] Nonair quality health, environmental impacts, and energy effects were not significant factors. No beyond-the-floor options for gas-fired boilers were identified.

An energy assessment is a beyond-the-floor standard being proposed for existing facilities. However, we are not proposing it as a beyond-the-floor option for new major source facilities since we believe it would not be cost effective because most projected new boilers or process heaters will be installed at existing major source facility which would have already conducted an energy assessment as required by this proposed rule. We also believe that any new greenfield major source facility having boilers or process heaters will be designed to operate with energy efficiency.

Based on the analysis discussed above, EPA decided to not go beyond the MACT floor level of control for new sources in this proposed rule. A detailed description of the beyond-the-floor consideration is in the memorandum "Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants" in the docket.

J. Consideration of whether to set standards for HCl and other acid gases under section 112(d)(4)

We are proposing to set a conventional MACT standard for HCl and, for the reasons explained elsewhere in today's notice, 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 section 112(d)(4) for HCl and each of the other relevant HAP acid gases: Chlorine (Cl_2), hydrogen fluoride (HF), and hydrogen cyanide (HCN) [15] (since if it were regulated under section 112(d)(4), HCl may no longer be the appropriate surrogate for these other HAPs).[16] This section sets forth the requirements of 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 112(d)(4) and solicitation of comments, and explains how this case relates to prior decisions EPA has made under section 112(d)(4) with respect to HCl.

As a general matter, 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, 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 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.

The legislative history of section 112(d)(4) indicates that Congress did not intend for this provision to provide a mechanism for EPA to delay issuance of emission standards for sources of HAPs. Finally, the legislative history also indicates that a health-based emission limit under section 112(d)(4) should be set at the level at which no observable effects occur, with an ample margin of safety. S. Rep. 101–228 at 171–72.

It is clear the Administrator may exercise her discretionary authority under 112(d)(4) only with respect to pollutants with an health threshold. Where there is an established threshold, the Administrator interprets 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 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 HAPs 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 via the MACT standard. Each of these factors is directly relevant to the health and environmental outcomes at which section 112 of the Clean Air Act 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 health threshold, with an ample margin of safety.

EPA has exercised its discretionary authority under section 112(d)(4) in a handful of prior actions setting emissions standards for other major source categories, including the emissions standards issued in 2004 for commercial and industrial boilers and process heaters, which were vacated on other grounds by the U.S. Court of Appeals for the D.C. Circuit. In both the Pulp and Paper MACT, 63 FR at 18765 (April 15, 1998), and Lime Manufacturing MACT, 67 FR at 78054 (December 20, 2002), EPA invoked 112(d)(4) for HCl emissions for discrete units within the facility. In those actions, EPA concluded that HCl had an established health threshold (in those cases it was interpreted as the reference concentration for chronic effects, or RfC) and 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 section 112(d)(4) for HCl under the circumstances of those actions. 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 a more recent action, EPA decided not to propose a health-based emission standard for HCl

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[14] Memorandum "Development (2010) of Fuel Switching Costs and Emission Reductions for Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants," April 2010.

[15] Before considering whether to exercise her discretion under section 112(d)(4) for a particular pollutant, the Administrator must first conclude that a health threshold has been established for the pollutant.

[16] HCl 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.,* HCN) 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.

emissions under section 112(d)(4) for Portland Cement facilities, 74 FR at 21154 (May 6, 2009). EPA has never implemented a NESHAP that used section 112(d)(4) with respect to HF, Cl_2 or HCN.[17]

Since any emission standard under 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. 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 reference concentration (RfC) for the inhalation of HCl of 20 $\mu g/m^3$. 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[18]) 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,[19] 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 HAPs or to a combination of HAPs 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 know 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 (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). However, we currently lack information on the peak short-term emissions of HCl from boilers, 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;
4. We are aware of no studies explicitly addressing the toxicity of mixtures of HCl with other respiratory irritants. However, many of the other HAPs (and criteria pollutants) emitted by boilers 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 boilers can be located among 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 section 112(d)(4). The legislative history states that employing a section 112(d)(4) standard rather than a conventional MACT standard "shall not result in adverse environmental effects which would otherwise be reduced or eliminated." S. Rep. 101–228 at 171. 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 nitrogen oxides are causing aquatic and/or terrestrial acidification, with accompanying ecological impacts, the deposition of hydrochloric acid could exacerbate these impacts. Being mindful of the legislative history, it is appropriate to consider potential adverse environmental effects in addition to adverse health effects when setting an emission standard for HCl under section 112(d)(4).

Because the statute requires an ample margin of safety, it would be reasonable to set any section 112(d)(4) emission standard for a pollutant with a health threshold at a level that at least assures that, for the sources in the controlled category or subcategory, persons exposed to emissions of the pollutant would not experience the adverse health effects on which the threshold is based. 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. Public comments are invited on our information and conclusion.

When Congress established the technology-based MACT program in the 1990 Clean Air Act Amendments, it recognized the challenges involved in evaluating health risk. Determining an emission standard that will protect the public health with an ample margin of safety is complex, in part because of the limited data available on cumulative impacts. In order to assess the feasibility of health-based standards in this rule, the agency believes it would need additional facility-specific emissions information. Such information would enable us to develop model plants for the eleven subcategories considered in the proposed rule and allow us to conduct the dispersion modeling necessary to establish health-based emission limits. These limits would need to be established to ensure that exposure is below the health threshold for sources in the subcategory, and account for the possibility of multiple exposures from co-located sources as well as potential short-term increases in emissions for these sources and their short-term impacts. Currently, the Agency has very limited information on facility-specific emissions, plant configurations, and overall fence-line characteristics for this large and diverse source category. This information is a precondition to establishing health-based emission standards that provide an ample margin of safety. To this end, the Agency is requesting information on these factors from the regulated community and others to allow us to evaluate the appropriateness and viability of health-based emission limits.

EPA specifically requests comment on the following issues. Additional information on these issues is important to implement section 112(d)(4) in a reasonable and appropriate manner, if we were to establish emissions standards under that provision. First,

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[17] EPA has not classified HF, chlorine gas, or HCN with respect to carcinogenicity. However, at this time the Agency is not aware of any data that would suggest any of these HAPs are carcinogens.

[18] "Sensitive subgroups" may refer to particular life stages, such as children or the elderly, or to those with particular medical conditions, such as asthmatics.

[19] California EPA considered acute toxicity and established a 1-hour reference exposure level (REL) of 2.1 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.

EPA requests comment on whether it would be appropriate to establish section 112(d)(4) standards for each acid gas described above, or whether EPA could set a single 112(d)(4) standard for one of the acid gases as a surrogate for the other acid gases. Commenters who believe a surrogate would be appropriate should also address the mechanism that should be used to determine the appropriate surrogate. In order to set individual standards under section 112(d)(4) for each acid gas, we would need to be able to conclude that each has an appropriate health threshold, that there is no scientific evidence that they are carcinogenic, and that the emission standard for each uses the best available science to consider the possibility of toxicologic interactions with the other emitted gases. Alternatively, if we were to establish a health-based emission standard for one of the acid gases as a surrogate for the others, in addition to the above considerations, we would need to demonstrate, based on a knowledge of the effectiveness of scrubbers for controlling each of the acid gases, that the surrogate emission standard effectively ensures that ambient levels of each of the other acid gases do not exceed their respective chronic health thresholds.

EPA also solicits comments on whether there would be an additive effect if individual section 112(d)(4) standards are established for each acid gas, and if so, how we would simulate that effect. Individual acid gas standards under section 112(d)(4) would likely be established using the hazard quotient (HQ) approach, under which we would develop the ratio of the maximum ambient level to the chronic threshold. However, this approach would not by itself account for potential toxicologic interactions. Since all of the acid gases are respiratory irritants, one way to account for potential toxicologic interactions of these pollutants would be the use of the hazard index (HI) approach, as described in EPA's "Guideline for the Health Risk Assessment of Chemical Mixtures." EPA requests comment on that approach, and on whether there are any other approaches to address such additive effects.

Additionally, EPA requests comment on whether we should consider the affected sources (boilers) by themselves, or whether we should consider all HAP emissions at the facility when developing a 112(d)(4) standard. Given that section 112(d)(4) requires an "ample margin of safety," EPA believes it should consider all reasonable circumstances in order to ensure such a margin. Since boilers are, in many cases, located at industrial sites with significant additional sources of HAP (e.g., petroleum refineries, furniture manufacturers, etc.), EPA requests comment on how we should consider the potential interactions of acid gases with other emitted respiratory irritants at these locations if we were to develop emission limits under section 112(d)(4). Commenters are requested to provide any actual data that is available to make this type of demonstration. If no data are available, we request comment on whether such a demonstration could be made using a bounding calculation.

EPA also requests comment on whether we should consider HAP emissions from neighboring facilities, and, if so, what the geographic scope of such consideration should be (*e.g.,* 1 km, 3 km, etc.). We note that consideration of emissions from nearby facilities is a more difficult task than consideration of facility-wide emissions, since it requires information on all potential HAP emissions near all of the locations with boilers. Therefore, we request comment on whether such emissions should be considered in setting section 112(d)(4) emissions standards, and if so, how they should be considered. For example, the consideration could be limited in geographic scope (*e.g.,* a radius of 3 km), or could be based on "average" or "high-end" ambient levels of respiratory irritants seen in recent monitoring data or modeled estimates, since site-specific data might not be available on all respiratory irritants.

Further, EPA requests comment on how to appropriately simulate all reasonable facility/exposure situations (*e.g.,* using worst-case facility emissions coupled with worst-case population proximity, average emissions and population, or 90th percentile emissions and population). Such a simulation could be based on a sequential examination of the facilities with the highest-emitting boilers on-site using site-specific data, or it could use screening or bounding methodologies with high-end or worst-case exposure assumptions to remove facilities from a more site-specific examination. We request comment on these and other approaches.

Finally, we considered the fact that setting conventional MACT standards for HCl as well as PM (as a surrogate for metals including manganese) would result in significant reductions in emissions of other pollutants, most notably SO_2, non-condensable PM, and other non-HAP acid gases (*e.g.,* hydrogen bromide) and would likely also result in additional reductions in emissions of mercury and other HAP metals (*e.g.,* selenium). The additional reductions of SO_2 alone attributable to the proposed MACT standard for HCl are estimated to be 340,000 tons per year in the third year following promulgation of the proposed HCl standard. These are substantial reductions with substantial public health benefits. Although MACT standards may directly address only HAPs, not criteria pollutants, Congress did recognize, in the legislative history to section 112(d)(4), that MACT standards would have the collateral benefit of controlling criteria pollutants as well and viewed this as an important benefit of the air toxics program.[20] Therefore, even where EPA concludes a HAP has a health threshold, the Agency may consider such benefits as a factor in determining whether to exercise its discretion under section 112(d)(4).

Given the limitations of the currently available information (i.e., the HAP mix where boilers are located, and the cumulative health impacts from co-located sources), the environmental effects of HCl, and the significant co-benefits of setting a conventional MACT standard for HCl, the Administrator is proposing not to exercise her discretion to use section 112(d)(4).

This conclusion is not contrary to EPA's prior decisions where we found it appropriate to exercise the discretion to invoke the authority in section 112(d)(4) for HCl, since the circumstances in this case differ from previous considerations. Boilers and process heaters differ from the other source categories for which EPA has exercised its authority under section 112(d)(4) in ways that affect consideration of any health threshold for HCl. Commercial and industrial boilers and process heaters are much more likely to be co-located with multiple other sources of HAPs than are pulp and paper mills and lime manufacturing facilities. In addition, boilers and process heaters are often located at facilities in heavily populated urban areas where many other sources of HAPs 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.

Given the particular complexities of this source category (the location of boilers and process heaters near other significant sources of HAP emissions

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[20] *See* S. Rep. No. 101–228, 101st Cong. 1st sess. At 172

and the use of HCl as a surrogate for other HAPs), we solicit comment on all of the conclusions in this section, including the way the agency has used 112(d)(4) previously, and in particular whether it would be feasible and appropriate to establish such a standard and, if so, the methodology by which it could be established.

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 requirement of this proposed rule. These requirements are described in detail in sections IV.K to IV.N. 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 facilities that must implement them.

We are proposing that compliance with the emission limits for PM, HCl, mercury, CO, and D/F be demonstrated by an initial performance test. To ensure continuous compliance with the proposed PM, HCl, and mercury emission limits, this proposed rule would require continuous parameter monitoring of control devices and recordkeeping. Additionally, this proposed rule would require annual performance tests to ensure, on an ongoing basis, that the air pollution control device is operating properly and its performance has not deteriorated. If initial compliance with the mercury and/or HCl emission limits are demonstrated by a fuel analysis performance test, this proposed rule would require fuel analyses monthly, with compliance determined based on an annual average.

We evaluated the feasibility and cost of applying PM CEMS to boilers and process heaters. CEMS have been used in Europe to monitor PM emissions from a variety of industrial sources. Several electric utility companies in the United States 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 Performance Specifications (PS) for PM CEMS (69 FR 1786, January 12, 2004). PS for PM CEMS are established under PS–11 in appendix B to 40 CFR part 60 for evaluating the acceptability of a PM CEM used for determining compliance with the emission standards on a continuous basis. For PM CEM monitoring, capital costs were estimated to be $88,000 per unit and annualized costs were estimated to be $33,000 per unit. We determined that requiring PM CEMS for units with heat input capacity greater or equal to 250 MMBtu/hr and combusting either coal, biomass, or oil is a reasonable monitoring option. We are requesting comment on the application of PM CEMS to boilers and process heaters, and the use of data from such systems for compliance determinations under this proposed rule.

We reviewed cost information for CO CEMS to make the determination on whether to require CO CEMS or conducting annual CO testing to demonstrate continuous compliance with the CO emission limit. In evaluating the available cost information, we determined that requiring CO CEMS for units with heat input capacities greater or equal to 100 MMBtu/hr is reasonable. This proposed rule would require units with heat input capacities less than 100 MMBtu/hr to conduct initial and annual performance (stack) tests.

The majority of test methods that this proposed rule would require for the performance stack tests have been required under many other EPA standards. The only applicable voluntary consensus standard identified is ASTM Method D6784–02 (Ontario Hydro). The majority of emissions tests upon which the proposed emission limits are based were conducted using these test methods.

When a performance test is conducted, we are proposing that parameter operating limits be determined during the tests. Performance tests to demonstrate compliance with any applicable emission limits are either stack tests or fuel analysis or a combination of both.

To ensure continuous compliance with the proposed emission limits 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 limits 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 opacity monitoring except for wet scrubbers; pH, pressure drop and liquid flowrate for wet scrubbers; and sorbent injection rate for dry scrubbers. You must also install a bag leak detection system for fabric filters. If you cannot monitor opacity for control systems with an ESP then you must monitor the secondary current and voltage or total power input for the ESP. 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 source elected to demonstrate compliance with the HCl or mercury 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 or mercury 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 limits, 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, mercury, sample collection, and sample preparation are included in this proposed rule.

If you 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.

For boilers and process heaters with heat input capacities greater or equal to 100 MMBtu/hr, we are proposing that CO be continuously monitored to demonstrate that average CO emissions, on a 30-day rolling average, are at or below the proposed CO limit.

For boilers and process heaters with heat input capacities between 10 and 100 MMBtu/hr, we are proposing that a performance stack test of CO emissions be conducted to demonstrate compliance with the CO emission limit.

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 the 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 sources and could only be used between boilers and process heaters in the same subcategory at a particular affected source. Also, owners or operators of existing sources subject to the Industrial Boiler NSPS (40 CFR part 60, subparts Db and Dc) 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.

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 boiler and process heater NESHAP. Further, emissions averaging would not be permitted between two or more different affected sources. Finally, new 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, the 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 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 sources because they can be designed and constructed with compliance in mind.

With concern about the equivalency of emissions reductions from averaging and non-averaging in mind, we are also proposing under the emission averaging provision caps on the current emissions from each of the sources in the averaging group. The emissions for each unit in the averaging group would be capped at the emission level being achieved on the effective date of the final rule. These caps would ensure that emissions do not increase above the emission levels that sources currently are designed, operated, and maintained to achieve. In the absence of performance tests, in documenting these caps, these sources will document the type, design, and operating specification of control devices installed on the effective date of the final rule to ensure that existing controls are not removed or operated less efficiently. By including this provision in this proposed rule, we would further ensure that emission averaging results in environmental benefits equivalent to or better than without emission averaging.

In addition, we are proposing that a discount factor of ten percent would be applied when emissions averaging is used. This discount factor will further ensure that averaging will be at least as stringent as the MACT floor limits in the absence of averaging. The EPA is soliciting comment on use of a discount factor and whether ten percent is the appropriate discount factor. 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 rational for the HON emissions averaging provisions were provided in the preamble to the final HON (59 FR 19425, April 22, 1994).

M. How did EPA determine compliance times for the proposed rule?

Section 112 of the CAA specifies the dates by which affected sources must comply with the emission standards. New or reconstructed units must be in compliance with this proposed rule immediately upon startup or [DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER], whichever is later. Existing sources are allowed 3 years to comply with the final rule. This is the maximum period allowed by the CAA. 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 boilers, as well as obtain permits for the use of add-on controls.

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 subpart DDDDD. We evaluated the General Provisions requirements and included those we determined to be the minimum notification, recordkeeping, and reporting necessary to ensure compliance with, and effective enforcement of, this proposed rule.

We are also requiring that you keep daily records of the total fuel use by each affected source, subject to an emission limit or work practice standard, 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. This information is necessary to ensure that the affected source is complying with the emission limits from the correct subcategory.

We would require additional recordkeeping if you chose to comply with the chlorine or mercury fuel input option. You would need to keep records of the calculations and supporting information used to develop the chlorine or mercury 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 3 years of your operating permit, you will need to obtain a revised permit to incorporate this proposed rule. If you are in the last 2 years of your operating permit, you will need to incorporate this proposed rule into the next renewal of your permit.

P. Alternate Standard for Consideration

As discussed above, EPA is proposing a definition of non-hazardous solid waste under RCRA in a concurrent notice. The proposed CAA section 112(d) standards for boilers and process heaters were developed considering that proposed definition of solid waste. Therefore, the emission limits presented in Tables 1 through 5 above are based on subcategories established considering sources that are ICI boilers and process heaters under the proposed definition of solid waste under RCRA. However, the RCRA proposal also identifies and solicits comment on an alternative approach for defining solid waste, under which more units would be considered solid waste incineration units than under the proposed definition. As such, the alternative approach for defining solid waste under RCRA would result in a different, smaller population of units being covered by Boiler MACT. Consistent with EPA's solicitation of comment on an alternative proposed definition of solid waste under RCRA, we calculated MACT floors using emission rates for units that would be ICI boilers and process heaters under that alternative definition, using the same statistical procedures that were used to calculate the standards that are being proposed. Table 6 reflects that calculation of MACT floor limits for the existing source subcategories that would be changed by the alternative definition of solid waste identified in the concurrent RCRA proposal, compared to the proposed definition of solid waste in that proposal. The MACT floor limits for the remaining existing source subcategories (Gas 1, Gas 2, and Liquid) would not change under the alternative definition of solid waste on which EPA is soliciting comment in the concurrent RCRA proposal, and are therefore not included in Table 8 because the MACT floor limits for those subcategories would be the same under the alternative definition of solid waste as under the proposed definition.

TABLE 8—EXISTING MACT FLOOR LIMITS USING THE "ALTERNATIVE APPROACH" UNDER CONSIDERATION AND COMMENT IN THE CONCURRENTLY PROPOSED RCRA RULE

[Pounds per million British thermal units]

Subcategory	Particulate matter (PM)	Hydrogen chloride (HCl)	Mercury (Hg)	Carbon monoxide (CO) (ppm @ 3% oxygen)	Dioxins/ Furans (total TEQ) (ng/dscm) commat; 7% O_2
Existing—Coal Stoker	0.03	0.02	4.0E–06	40	0.003
Existing—Coal Fluidized Bed	0.03	0.02	4.0E–06	50	0.008
Existing—Pulverized Coal	0.03	0.02	4.0E–06	90	0.004

TABLE 8—EXISTING MACT FLOOR LIMITS USING THE "ALTERNATIVE APPROACH" UNDER CONSIDERATION AND COMMENT IN THE CONCURRENTLY PROPOSED RCRA RULE—Continued

[Pounds per million British thermal units]

Subcategory	Particulate matter (PM)	Hydrogen chloride (HCl)	Mercury (Hg)	Carbon monoxide (CO) (ppm @ 3% oxygen)	Dioxins/Furans (total TEQ) (ng/dscm) commat; 7% O_2
Existing—Biomass Stoker	0.02	0.03	5.0E–07	180	0.00005
Existing—Biomass Fluidized Bed	0.02	0.03	5.0E–07	10,650	0.1
Existing—Biomass Suspension Burner/Dutch Oven	0.02	0.03	5.0E–07	1,060	0.3
Existing—Biomass Fuel Cells	0.02	0.03	5.0E–07	460	0.02

Comparing the emissions limits in Table 1 (based on the proposed definition of solid waste) with those in Table 8 (based on the alternative definition of solid waste), the MACT emission limits for PM and mercury for the biomass subcategories would be less stringent if they are based on the alternative definition of solid waste while the HCl emission limits for the coal and biomass subcategories would be more stringent if they are based on the alternative definition.

The potential emissions reductions if the MACT floor limits are calculated based on the alternative definition of solid waste would be generally lower than the potential emissions reductions for MACT floors based on the proposed definition of solid waste, because 280 fewer boilers and process heaters would be subject to the boiler and process heater MACT standards under the alternative definition. These units would instead be considered CISWI units under the alternative definition of solid waste. For example, mercury emissions reduction would be 7 tons per year based on the alternative definition of solid waste (compared to 8 tons per year based on the proposed definition) and HCl emissions reduction would be 5,100 tons per year based on the alternative definition (compared to 37,000 tons per year based on the proposed definition). Most (181) of the 280 units that would be considered CISWI units under the alternative definition of solid waste proposed under RCRA are biomass-fired boilers or process heaters, with the others being in the coal and liquid fuel subcategories.

The resulting total national cost impact for existing boilers and process heaters of the proposed emission limits based on the alternative definition of solid waste would be 8.0 billion dollars in capital expenditures and 2.4 billion dollars per year in total annual costs. This compares to $9.5 billion in capital costs and $2.9 billion in annual costs under the proposed definition of solid waste in the RCRA proposed rule. Table 9 of this preamble shows the capital and annual cost impacts for each subcategory under the alternative definition of solid waste. Costs include testing and monitoring costs, but not recordkeeping and reporting costs.

TABLE 9—SUMMARY OF CAPITAL AND ANNUAL COSTS FOR EXISTING SOURCES UNDER THE ALTERNATIVE SOLID WASTE DEFINITION

Source	Subcategory	Estimated/projected number of affected units	Capital costs ($10^6$$)	Annualized cost ($10^6$$/yr)
Existing Units	Coal units	525	3,861	1,508
	Biomass units	239	1,250	317
	Liquid units	791	1,352	417
	Gas (NG/RG) units	11,524	75	259
	Gas (other) units	196	1,476	434
Energy Assessment	ALL	1,551 facilities		24.9

A discussion of the methodology used to estimate cost impacts is presented in "Methodology and Results of Estimating the Cost of Complying with the Industrial, Commercial, and Institutional Boiler and Process Heater NESHAP (2010)" in the Docket.

We are soliciting public comments on the emission limits listed in Table 6 of this preamble, consistent with EPA's solicitation of comments on the alternative definition of solid waste concurrently proposed under RCRA. As explained above, the MACT floor limits proposed today are based on the proposed definition of solid waste under RCRA. However, because EPA is seeking comment on an alternative definition of solid waste under RCRA, the Agency believes it is necessary to also solicit comment on what the MACT floor limits would be based on the universe of sources that would be subject to the boiler and process heater MACT under that alternative definition.

V. Impacts of the Proposed Rule

A. What are the air impacts?

Table 10 of this preamble illustrates, for each basic fuel subcategory, the emissions reductions achieved by the proposed rule (*i.e.*, the difference in emissions between a boiler or process heater controlled to the floor level of control and boilers or process heaters at the current baseline) for new and existing sources. Nationwide emissions of selected HAP (*i.e.*, HCl, HF, mercury, metals, and VOC) will be reduced by 43,000 tons per year for existing units and 15 tons per year for new units. Emissions of HCl will be reduced by 37,000 tons per year for existing units and 9 tons per year for new units. Emissions of mercury will be reduced by 8 tons per year for existing units and 2.6 pounds per year for new units. Emissions of filterable PM will be reduced by 50,100 tons per year for existing units and 130 tons per year for new units. Emissions of non-mercury metals (*i.e.,* antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium) will be reduced by 3,200 tons per year for existing units and will be reduced by 0.6 ton per year for new units. In addition, emissions of SO_2 are estimated to be reduced by 340,000 tons per year for existing sources and 500 tons per year for new sources. Emissions of dioxin/furans, on a total mass basis, will be reduced by 722 grams per year for existing units and 1 gram per year for new units. A discussion of the methodology used to estimate emissions and emissions reductions is presented in "Estimation of Baseline Emissions and Emissions Reductions for Industrial, Commercial, and Institutional Boilers and Process Heaters (2010)" in the docket.

TABLE 10—SUMMARY OF EMISSIONS REDUCTIONS FOR EXISTING AND NEW SOURCES

[Tons/yr]

Source	Subcategory	HCl	PM	Non mercury metals [a]	Mercury	VOC
Existing Units	Coal units	35,450	17,000	770	7.1	490
	Biomass units	520	22,500	230	0.2	760
	Liquid units	840	10,400	2,200	0.00005	290
	Gas 1 (NG/RG) units	9	130	1.2	0.01	72
	Gas 2 (other) units	220	0	0	0.2	170
New Units	Coal units	0	0	0	0	0
	Biomass units	0	0	0	0	0
	Liquid units	9	130	0.6	0.0007	3
	Gas 1 units	0.01	0.1	0.001	0.000008	0.01
	Gas 2 units	1	4	0.01	0.0006	1

[a] Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

B. What are the water and solid waste impacts?

The EPA estimated the additional water usage that would result from installing wet scrubbers to meet the emission limits for HCl would be 2,400 million gallons per year for existing sources and 200,000 gallons per year for new sources. In addition to the increased water usage, an additional 730 million gallons per year of wastewater would be produced for existing sources and 140,000 gallons per year for new sources. The annual costs of treating the additional wastewater are $4.0 million for existing sources and $774 for new sources. These costs are accounted for in the control costs estimates.

The EPA estimated the additional solid waste that would result from the MACT floor level of control to be 81,000 tons per year for existing sources and 149,800 tons per year for new sources. Solid waste is generated from flyash and dust captured in PM and mercury controls as well as from spent carbon that is injected into exhaust streams or used to filter gas streams. The costs of handling the additional solid waste generated are $3.4 million for existing sources and $6.3 million for new sources. These costs are also accounted for in the control costs estimates.

A discussion of the methodology used to estimate impacts is presented in "Estimation of Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (2010)" in the Docket.

C. What are the energy impacts?

The EPA expects an increase of approximately 2.995 million kilowatt hours (kWh) in national annual energy usage as a result of the proposed rule. Of this amount, 2,944 million kWh would be from existing sources and 11 million kWh are estimated from new sources. The increase results from the electricity required to operate control devices, such as wet scrubbers, electrostatic precipitators, and fabric filters which are expected to be installed to meet the proposed rule. Additionally, the EPA expects work practice standards such as boilers tune-ups and combustion controls will improve the efficiency of boilers, resulting in an estimated fuel savings of 42 trillion BTU each year from existing sources and an additional 100,000 million BTU each year. This fuel savings estimate includes only those fuel savings resulting from gas, liquid, and coal fuels and it is based on the assumption that the work practice standards will achieve 1 percent improvement in efficiency.

D. What are the control costs?

To estimate the national cost impacts of the proposed rule for existing sources, we developed average baseline emission factors for each fuel type/control device combination based on the emission data obtained and contained in the Boiler MACT emission database. If a unit reported emission data, we assigned its unit-specific emission data as its baseline emissions. For units that did not report emission data, we assigned the appropriate emission factors to each existing unit in the inventory database, based on the average emission factors for boilers with similar fuel, design, and control devices. We then compared each unit's baseline emission factors to the proposed MACT floor emission limit to determine if control devices were needed to meet the emission limits. The control analysis considered fabric filters, carbon bed adsorbers, and activated carbon injection to be the primary control devices for mercury control, electrostatic precipitators for units meeting mercury limits but requiring additional control to meet the PM limits, wet scrubbers to meet the HCl limits, tune-ups, replacement burners, and combustion controls for CO and organic HAP control, and carbon injection for dioxin/furan control. We identified where one control device could achieve reductions in multiple pollutants, for example a fabric filter was expected to achieve both PM and mercury control in order to avoid overestimating the costs. We also included costs for testing and monitoring requirements contained in the proposed rule. The resulting total national cost impact of the proposed rule is 9.5 billion dollars in capital expenditures and 3.2 billion dollars per year in total annual costs. Considering estimated fuel savings resulting from work practice standards and combustion controls, the total annualized costs are reduced to 2.9 billion dollars. The total capital and annual costs include costs for control devices, work practices, testing and monitoring. Table 11 of this preamble shows the capital and annual cost impacts for each subcategory. Costs include testing and monitoring costs, but not recordkeeping and reporting costs.

TABLE 11—SUMMARY OF CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES

Source	Subcategory	Estimated/projected number of affected units	Capital costs (10^6\$)	Testing and monitoring annualized costs (10^6\$/yr)	Annualized cost (10^6\$/yr) (considering fuel savings)
Existing Units	Coal units	578	4,468	62.4	1,619
	Biomass units	420	2,003	35.5	609
	Liquid units	826	1,389	27.4	419
	Gas (NG/RG) units	11,532	75	0	(260)
	Gas (other) units	199	1,554	10.4	459
Energy Assessment	ALL	....	....	....	26
New Units	Coal units	0	0	0	0
	Biomass units	0	0	0	0
	Liquid units	11	12	0.5	6.1
	Gas (NG/RG) units	33	0.2	0	0.01
	Gas (other) units	2	5.5	0.14	1.7

Using Department of Energy projections on fuel expenditures, the number of additional boilers that could be potentially constructed was estimated. The resulting total national cost impact of the proposed rule in the 3rd year is 17 million dollars in capital expenditures and 6.2 million dollars per year in total annual costs, when considering a 1 percent fuel savings.

Potential control device cost savings and increased recordkeeping and reporting costs associated with the emissions averaging provisions in the proposed rule are not accounted for in either the capital or annualized cost estimates.

A discussion of the methodology used to estimate cost impacts is presented in "Methodology and Results of Estimating the Cost of Complying with the Industrial, Commercial, and Institutional Boiler and Process Heater NESHAP (2010)" in the Docket.

E. What are the economic impacts?

The economic impact analysis (EIA) that is included in the RIA shows that the expected prices for industrial sectors could be 0.01 percent higher and domestic production may fall by about 0.01 percent. Because of higher domestic prices imports may rise by 0.01 percent. In addition, impacts to affected energy markets show that prices may rise by 0.04 percent.

Social costs are estimated to also be $2.9 billion in 2008 dollars. This is estimated to be made up of a $0.8 billion loss in domestic consumer surplus, a $2.5 billion loss in domestic producer surplus, a $0.1 billion increase in rest of the world surplus, and a $0.4 billion in net fuel savings not modeled in a way that can be used to attribute it to consumers and producers.

EPA 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 3 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 Small Business Advocacy Review (SBAR) panel.

Precise job effect estimates cannot be estimated with certainty. 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").

Several empirical studies, including Morgenstern et al. (2002), suggest the net employment decline is zero or economically small (*e.g.,* Cole and Elliot, 2007; Berman and Bui, 2001). However, others show the question has not been resolved in the literature (Henderson, 1996; Greenstone, 2002). Morgenstern's paper uses a six-year panel (U.S. Census data for plant-level prices, inputs (including labor), outputs, and environmental expenditures) to econometrically estimate the production technologies and industry-level demand elasticities. Their identification strategy leverages repeat plant-level observations over time and uses plant-level and year fixed effects (*e.g.,* plant and time dummy variables). After estimating their model, Morgenstern show and compute the change in employment associated with an additional $1 million ($1987) in environmental spending. Their estimates covers four manufacturing industries (pulp and paper, plastics, petroleum, and steel) and Morgenstern, *et al.* present results separately for the cost, factor shift, and demand effects, as well as the net effect. They also estimate and report an industry-wide average parameter that combines the four industry-wide estimates and weighting them by each industry's share of environmental expenditures.

EPA has most often estimated employment changes associated with plant closures due to environmental regulation or changes in output for the regulated industry (EPA, 1999a; EPA, 2000). This analysis goes beyond what EPA has typically done in two ways. First, because the multimarket model provides estimates for changes in output for sectors not directly regulated, we were able to estimate a more comprehensive "demand effect." Secondly, parameters estimated in the Morgenstern paper were used to estimate all three effects ("demand," "cost," and "factor shift"). This transfer of results from the Morgenstern study is uncertain but avoids ignoring the "cost effect" and the "factor-shift effect."

We calculated "demand effect" employment changes by assuming that the number of jobs changes proportionally with multi-market model's simulated output changes. These results were calculated for all sectors in the EPA model that show a change in output. The total job losses are estimated to be approximately 6,000.

We also calculated a similar "demand effect" estimate that used the Morgenstern paper. To do this, we multiplied the point estimate for the total demand effect (−3.56 jobs per million ($1987) of environmental compliance expenditure) by the total environmental compliance expenditures used in the partial equilibrium model. For example, the job loss estimate is approximately 7,000 jobs (−3.56 × $3.5 billion × 0.60).[21]

We also present the results of using the Morgenstern paper to estimate employment "cost" and "factor-shift" effects (Table 1). Although using the Morgenstern parameters to estimate these "cost" and "factor-shift" employment changes is uncertain, it is helpful to compare the potential job gains from these effects to the job losses associated with the "demand" effect. Table 1 shows that using the Morgenstern point estimates of parameters to estimate the "cost" and "factor shift" employment gains may be greater than the employment losses using either of the two ways of estimating "demand" employment losses. The 95 percent confidence intervals are shown for all of the estimates based on the Morgenstern parameters. As shown, at the 95% confidence level, we cannot be certain if net employment changes are positive or negative.

Although the Morgenstern paper provides additional information about the potential job effects of environmental protection programs, there are several qualifications EPA considered as part of the analysis. First, EPA has used the weighted average parameter estimates for a narrow set of manufacturing industries (pulp and paper, plastics, petroleum, and steel). Absent other data and estimates, this approach seems reasonable and the estimates come from a respected peer-reviewed source. However, EPA acknowledges the proposed rule covers a broader set of industries not considered in original empirical study. By transferring the estimates to other industrial sectors, we make the assumption that estimates are similar in size. In addition, EPA assumes also that Morgenstern et al.'s estimates derived from the 1979–1991 still applicable for policy taking place in 2013, almost 20 years later. Second, the multi-market model only considers near term employment effects in a U.S. economy where production technologies are fixed. As a result, the modeling system places more emphasis on the short term "demand effect" whereas the Morgenstern paper emphasizes other important long term responses. For example, positive job gains associated with "factor shift effects" are more plausible when production choices become more flexible over time and industries can substitute labor for other production inputs. Third, the Morgenstern paper estimates rely on sector demand elasticities that are different from the demand elasticity parameters used in the multi-market model. As a result, the demand effects are not directly comparable with the demand effects estimated by the multi-market model. Fourth, Morgenstern identifies the industry average as economically and statistically insignificant effect (*i.e.,* the point estimates are small, measured imprecisely, and not distinguishable from zero.) EPA acknowledges this fact and has reported the 95 percent confidence intervals in Table 1. Fifth, Morgenstern's methodology assumes large plants bear most of the regulatory costs. By transferring the estimates, EPA assumes a similar distribution of regulatory costs by plant size and that the regulatory burden does not disproportionately fall on smaller plants.

TABLE 12—EMPLOYMENT CHANGES: 2013

Estimation method	1,000 Jobs
Partial equilibrium model (multiple markets) (demand effect only)	−5
Literature-based estimate (net effect [A + B + C below])	+3 (−6 to +12)
A. Literature-based estimate: Demand effect	−7 (−15 to +1)
B. Literature-based estimate: Cost effect	+5 (+2 to +8)
C. Literature-based estimate: Factor shift effect	+5 (0 to +10)

NOTE: Totals may not add due to independent rounding. 95 percent confidence intervals for literature-based estimates are shown in parenthesis.

F. What are the social costs and benefits of this proposed rule?

We estimate the monetized benefits of this proposed regulatory action to be $17 billion to $41 billion (2008$, 3 percent discount rate) in the implementation year (2013). The monetized benefits of the proposed regulatory action at a 7 percent discount rate are $15 billion to $37 billion (2008$). 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.[22] A summary of the monetized benefits estimates at discount rates of 3 percent and 7 percent is in Table 13 of this preamble.

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[21] Since Morgenstern's analysis reports environmental expenditures in $1987, we make an inflation adjustment the engineering cost analysis using GDP implicit price deflator (64.76/108.48) = 0.60).

[22] 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.

TABLE 13—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE PROPOSED BOILER MACT FOR MAJOR SOURCES IN 2013

[Billions of 2008$][1]

	Estimated emission reductions (tons per year)	Total monetized benefits (3% discount rate)	Total monetized benefits (7% discount rate)
$PM_{2.5}$	29,020	\$6.6 to \$16	\$6.0 to \$15.
$PM_{2.5}$ Precursors			
SO_2	339,996	\$10 to \$25	\$9.1 to \$22.
VOC	1,786	\$0.002 to \$0.005	\$0.002 to \$0.005.
Total		\$17 to \$41	\$15 to \$37.

[1] All estimates are for the implementation year (2013), and are rounded to two significant figures so numbers may not sum across rows. 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 hazardous air pollutants (HAPs) are not included.

These benefits estimates represent the total monetized human health benefits for populations exposed to less $PM_{2.5}$ in 2013 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 utilized the general approach and methodology on the laid out in Fann *et al.* (2009).[23]

To generate the benefit-per-ton estimates, we used a model to convert emissions of direct $PM_{2.5}$ and $PM_{2.5}$ 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[24] and the extended Six Cities cohort study.[25] In the 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[26] 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 carbon monoxide and hazardous air pollutants have not been monetized in this analysis, including reducing 330,000 tons of carbon monoxide, 37,000 tons of HCl, 1,000 tons of HF each year, 7.5 tons of mercury, 3,200 tons of other metals, and 720 grams of dioxins/furans 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 Regulatory Impact Analysis (RIA) for this proposed rule, which is available in the docket.

The social costs of this proposed rulemaking are estimated to be \$2.9 billion (2008\$) in the implementation year, and the monetized benefits are \$17 billion to \$41 billion (2008\$, 3 percent discount rate) for that same year. The benefits at a 7 percent discount rate are \$15 billion to \$37 billion (2008\$). Thus, net benefits of this rulemaking are estimated at \$14 billion to \$38 billion (2008\$, 3 percent discount rate) and \$12 billion to \$34 billion (2008\$, 7 percent discount rate). EPA believes that the benefits of the proposed rule are likely to exceed the costs even when taking into account the uncertainties in the cost and benefit estimates. A summary of the monetized benefits, social costs, and net benefits at discount rates of 3 percent and 7 percent is in Table 14 of this preamble.

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[23] 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.

[24] 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.

[25] Laden *et al.,* 2006. "Reduction in Fine Particulate Air Pollution and Mortality." *American Journal of Respiratory and Critical Care Medicine.* 173:667–672.

[26] 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 14—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE BOILER MACT (MAJOR SOURCES) IN 2013

[Millions of 2008$] [1]

	3% Discount rate	7% Discount rate
Proposed Option		
Total Monetized Benefits [2]	$17 to $41	$15 to $37.
Total Social Costs [3]	$2.9	$2.9.
Net Benefits	$14 to $38	$12 to $34.
Non-monetized Benefits	340,000 tons of carbon monoxide. 37,000 tons of HCl. 1,000 tons of HF. 7.5 tons of mercury. 3,200 tons of other metals. 720 grams of dioxins/furans. Health effects from NO_2 and SO_2 exposure. Ecosystem effects. Visibility impairment.	
Proposed Option with Alternate Solid Waste Definition		
Total Monetized Benefits [2]	$3.1 to $7.7	$2.8 to $6.9.
Total Social Costs [3]	$2.2	$2.2.
Net Benefits	$0.93 to $5.5	$0.64 to $4.7.
Non-monetized Benefits	280,000 tons of carbon monoxide. 5,100 tons of HCl. 1,100 tons of HF. 7.1 tons of mercury. 1,600 tons of other metals. 290 grams of dioxins/furans. Health effects from NO_2 and SO_2 exposure.	
	Ecosystem effects.	
	Visibility impairment.	

[1] All estimates are for the implementation year (2015), and are rounded to two significant figures.

[2] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of directly emitted $PM_{2.5}$ and $PM_{2.5}$ precursors such as NO_X and SO_2. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure.

[3] The methodology used to estimate social costs for one year in the multimarket model using surplus changes results in the same social costs for both discount rates.

For more information on the benefits analysis, please refer to the RIA for this rulemaking, which is available in the docket.

VI. Public Participation and Requests for Comment

We request comment on all aspects of this proposed rule.

In 2004 we published a final rule for boilers and process heaters located at major source facilities (69 FR 55218, September 13, 2004). The final rule was vacated and remanded by the Court on June 19, 2007. We are reissuing our proposal, in response to the Court's decisions, in this notice. We received many comments on that vacated rule during its rulemaking and have attempted to take all those comments into account in this action. This proposal includes a variety of changes from the vacated rule, mostly centered on emission limits for the various HAP and subcategories.

During this rulemaking, we conducted outreach to small entities and convened a Small Business Advocacy Review (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 small entity representatives (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 on the rulemaking, possible regulatory approaches, preliminary cost and economic impacts, and possible rulemaking alternatives. We met with SERs from the industries 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.

VII. Relationship of This Proposed Action to Section 112(c)(6) of the CAA

Section 112(c)(6) of the CAA requires EPA to identify categories of sources of seven specified pollutants to assure that sources accounting for not less than 90 percent of the aggregate emissions of each such pollutant are subject to standards under CAA Section 112(d)(2) or 112(d)(4). EPA has identified "Industrial Coal Combustion," "Industrial Oil Combustion," Industrial Wood/Wood Residue Combustion," "Commercial Coal Combustion," "Commercial Oil Combustion," and "Commercial Wood/Wood Residue Combustion" as source categories that emits two of the seven CAA Section 112(c)(6) pollutants: POM and mercury. (The POM emitted is composed of 16 polyaromatic hydrocarbons and extractable organic matter.) In the **Federal Register** notice *Source Category Listing for Section 112(d)(2) Rulemaking Pursuant to Section 112(c)(6) Requirements,* 63 FR 17838, 17849, Table 2 (1998), EPA identified "Industrial Coal Combustion," "Industrial Oil Combustion," "Industrial Wood/Wood Residue Combustion," "Commercial Coal Combustion," "Commercial Oil Combustion," and "Commercial Wood/Wood Residue Combustion" as source category "subject to regulation" for purposes of CAA Section 112(c)(6) with respect to the CAA Section 112(c)(6) pollutants that these units emit.

Specifically, as byproducts of combustion, the formation of POM is effectively reduced by the combustion and post-combustion practices required to comply with the CAA Section 112 standards. Any POM that do form during combustion are further controlled by the various post-combustion controls. The add-on PM control systems (either fabric filter or wet scrubber) and activated carbon injection in the fabric filter-based systems further reduce emissions of these organic pollutants, and also reduce mercury emissions, as is evidenced by performance data. Specifically, the emission tests obtained at currently operating units show that the proposed MACT regulations will reduce mercury emissions by about 86 percent. It is, therefore, reasonable to conclude that POM emissions will be substantially controlled. Thus, while this proposed rule does not identify specific numerical emission limits for POM, emissions of POM are, for the reasons noted below, nonetheless "subject to regulation" for purposes of Section 112(c)(6) of the CAA.

In lieu of establishing numerical emissions limits for pollutants such as POM, we regulate surrogate substances. While we have not identified specific numerical limits for POM, we believe CO serves as an effective surrogate for this HAP, because CO, like POM, is formed as a byproduct of combustion.

Consequently, we have concluded that the emissions limits for CO function as a surrogate for control of POM, such that it is not necessary to propose numerical emissions limits for POM with respect to boilers and process heaters to satisfy CAA Section 112(c)(6).

To further address POM and mercury emissions, this proposed rule also includes an energy assessment provision that encourages modifications to the facility to reduce energy demand that lead to these emissions.

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review

Under Executive Order 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 Office of Management and Budget (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 14 of this preamble.

B. Executive Order 13132, Federalism

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

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

C. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

Executive Order 13175 (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." This proposed rule does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. This proposed rule imposes requirements on owners and operators of specified area sources and not tribal governments. We do not know of any industrial, commercial, or institutional boilers owned or operated by Indian tribal governments. However, if there are any, the effect of this proposed rule on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to this proposed rule. EPA specifically solicits additional comment on this proposed rule from tribal officials.

D. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be "economically significant" as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that 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 not subject to Executive Order 13045 because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. The reason for this determination is that this proposed rule is based solely on technology performance.

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.

E. Unfunded Mandates Reform Act of 1995

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

We have determined that 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 Industrial Boilers and Process Heaters NESHAP" under section 202 of the UMRA which is summarized below.

1. Statutory Authority

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

Section 112(d) of the CAA directs us to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT based standards. This NESHAP applies to all industrial, commercial, and institutional boilers and process heaters located at major sources of HAP emissions.

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

The regulatory alternative upon which the proposed rule is based represents the MACT floor for industrial boilers and process heaters and, as a result, it is the least costly and least burdensome alternative.

2. Social Costs and Benefits

The regulatory impact analysis prepared for the proposed rule including the Agency's assessment of costs and benefits, is detailed in the "Regulatory Impact Analysis for the Proposed Industrial Boilers and Process Heaters MACT" in the docket. Based on estimated compliance costs associated with the proposed rule and the predicted change in prices and production in the affected industries, the estimated social costs of the proposed rule are $2.9 billion (2008 dollars).

It is estimated that 3 years after implementation of the proposed rule, HAPs would be reduced by thousands of tons, including reductions in hydrochloric acid, hydrogen fluoride, metallic HAP including mercury, and several other organic HAP from boilers and process heaters. 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 29 thousand tons of $PM_{2.5}$ and 340 thousand tons of SO_2. These reductions occur within 3 years after the implementation of the proposed regulation 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). While we are unable to monetize the benefits associated with the HAP emissions reductions, 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 2013 associated with the implementation of the proposed alternative is a range from $17 billion (2008 dollars) to $41 billion (2008 dollars) when using a 3 percent discount rate (or from $15 billion (2008 dollars) to $37 billion (2008 dollars) when using a 7 percent discount rate). This estimate, at a 3 percent discount rate, is about $14 billion (2008 dollars) to $38 billion (2008 dollars) higher than the estimated social costs shown earlier in this section. The general approach used to value benefits is discussed in more detail earlier in this preamble. For more detailed information on the benefits estimated for the proposed rulemaking, refer to the RIA in the docket.

3. Future and Disproportionate Costs

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

We do not believe that there will be any disproportionate budgetary effects of the proposed rule on any particular areas of the country, State or local governments, types of communities (*e.g.,* urban, rural), or particular industry segments. See the results of the "Economic Impact Analysis of the Proposed Industrial Boilers and Process Heaters NESHAP," the results of which are discussed previously in this preamble.

4. Effects on the National Economy

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

The nationwide economic impact of the proposed rule is presented in the "Economic Impact Analysis for the Industrial Boilers and Process Heaters MACT" in the docket. This analysis provides estimates of the effect of the proposed rule on some of the categories mentioned above. The results of the economic impact analysis are summarized previously in this preamble. The results show that there will be a small impact on prices and output, and little impact on communities that may be affected by the proposed rule. In addition, there should be little impact on energy markets (in this case, coal, natural gas, petroleum products, and electricity). Hence, the potential impacts on the categories mentioned above should be small.

5. Consultation With Government Officials

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

In addition, we have determined that the proposed rule contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have some sources affected by the proposed rule, the impacts are not expected to be significant. Therefore, today's proposed rule is not subject to the requirements of section 203 of the UMRA.

F. 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: (1) A small business according to Small Business Administration (SBA) size standards by the North American Industry Classification System category of the owning entity. The range of small business size standards for the 40 affected industries ranges from 500 to 1,000 employees, except for petroleum refining and electric utilities. In these latter two industries, the size standard is 1,500 employees and a mass throughput of 75,000 barrels/day or less, and 4 million kilowatt-hours of production or less, respectively; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Because an initial screening analysis for impact on small entities indicated a likely significant impact for substantial numbers, 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.

(a) Panel Process and Panel Outreach

As required by section 609(b) of the RFA, as amended by SBREFA, EPA also has conducted outreach to small entities and on January 22, 2009 EPA's Small Business Advocacy Chairperson convened a Panel under section 609(b) of the RFA. 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 the Small Business Administration, and the Administrator of the Office of Information and Regulatory Affairs within the Office of Management and Budget.

As part of the SBAR Panel process we conducted outreach with representatives from 14 various small entities that would be affected by this rule. The small entity representatives (SERs) included associations representing schools, churches, hotels/motels, wood product facilities and manufacturers of home furnishings. 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 on the rulemaking, possible regulatory approaches, preliminary cost and economic impacts, and possible rulemaking alternatives. The Panel met with SERs from the industries that will be impacted directly by this rule on February 10, 2009 to discuss the outreach materials and receive feedback on the approaches and alternatives detailed in the outreach packet. (EPA also met with SERs on November 13, 2008 for an initial outreach meeting.) 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.

(1) Panel Recommendations for Small Business Flexibilities

The Panel recommended that EPA consider and seek comment on a wide range of regulatory alternatives to mitigate the impacts of the rulemaking on small businesses, including those flexibility options described below. The following section summarizes the SBAR Panel recommendations. EPA has proposed provisions consistent with four of the Panel's recommendations.

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 as well as summaries of both outreach meetings that were held with the SERs is included in the docket for this proposed rule. A summary of the Panel recommendations is detailed below. As noted above, this proposal includes proposed provisions for all but one of the Panel recommendations.

(a) Work Practice Standards

The panel recommended that EPA consider requiring annual tune-ups, including standardized criteria outlining proper tune-up methods targeted at smaller boiler operators. The panel further recommended that EPA take comment on the efficacy of energy assessments/audits at improving combustion efficiency and the cost of performing the assessments, especially to smaller boiler operators.

A work practice standard, instead of MACT emission limits, may be proposed if it can be justified under section 112(h) of the CAA, that is, it is impracticable to enforce the emission standards due to technical or economic limitations. Work practice standards could reduce fuel use and improve combustion efficiency which would result in reduced emissions.

In general, SERs commented that a regulatory approach to improve combustion efficiency, such as work practice standards, would have positive impacts with respect to the environment and energy use and save on compliance costs. The SERs were concerned with work practice standards that would require energy assessments and implementation of assessment findings. The basis of these concerns rested upon the uncertainty that there is no guarantee that there are available funds to implement a particular assessment's findings.

(b) Subcategorization

The Panel recommended that EPA allow subcategorizations suggested by the SERs, unless EPA finds that a subcategorization is inconsistent with the Clean Air Act.

SERs commented that subcategorization is a key concept that could ensure that like boilers are compared with similar boilers so that MACT floors are more reasonable and could be achieved by all units within a subcategory using appropriate emission reduction strategies. SERs commented that EPA should subcategorize based on fuel type, boiler type, duty cycle, and location.

(c) Health Based Compliance Alternatives (HBCA)

The Panel recommended that EPA adopt the HBCA as a regulatory flexibility option for the Boiler MACT rulemaking. The panel recognized, however, that EPA has concerns about its legal authority to provide an HBCA under the Clean Air Act, and EPA may ultimately determine that this flexibility is inconsistent with the Clean Air Act.

SERs commented that adopting an HBCA would perhaps be the most important step EPA could take to mitigate the serious financial harm the Boiler MACT would otherwise inflict on small entities using solid fuels nationwide and, therefore, HBCA should be a critical component of any future rule to lessen impact on small entities.

(d) Emissions Averaging

The Panel recommended that EPA consider a provision for emission averaging and long averaging times for the proposed emission limits.

SERs commented that a measure EPA should consider to lessen the regulatory burden of complying with Boiler MACT is to allow emissions averaging at sources with multiple regulated units. SERs commented that another approach that can aide small entity compliance is to set longer averaging times (*i.e.,* 30-days or more) rather than looking at a mere 3-run (hour) average for performance. Given the inherent variability in boiler performance, an annual or quarterly averaging period for all HAP would prevent a single spike in emissions from throwing a unit into non-compliance.

(e) Compliance Costs

The Panel recommended that EPA carefully weigh the potential burden of compliance requirements and consider for small entities options such as, emission averaging within facility, reduced monitoring/testing requirements, or allowing more time for compliance.

SERs noted that recordkeeping activities, as written in the vacated boiler MACT, would be especially challenging for small entities that do not have a dedicated environmental affairs department.

G. Paperwork Reduction Act

The information collection requirements in the proposed rule will be submitted for approval to the Office of Management and Budget under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* An Information Collection Request (ICR) document has been prepared by EPA (ICR No. 2028.05).

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 section 114 of the CAA (42 U.S.C. 7414). All information submitted to EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The proposed rule would require 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 $87.6 million. This includes 208,832 labor hours per year at a total labor cost of $19.8 million per year, and total non-labor capital costs of $67.8 million per year. This estimate includes initial and annual performance test, conducting and documenting an energy assessment, conducting and documenting a tune-up, semiannual excess emission reports, maintenance inspections, developing a monitoring plan, notifications, and recordkeeping. Monitoring, testing, tune-up and energy assessment costs and cost were also included in the cost estimates presented in the control costs impacts estimates in section IV.D of this preamble. The total burden for the Federal government (averaged over the first 3 years after the effective date of the standard) is estimated to be 93,648 hours per year at a total labor cost of $4.9 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 action, which includes this ICR, under Docket ID number EPA–HQ–OAR–2002–0058. 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. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after June 4, 2010, a comment to OMB is best assured of having its full effect if OMB receives it by July 6, 2010. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

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

This rulemaking involves technical standards. The EPA cites the following standards in the proposed rule: EPA Methods 1, 2, 2F, 2G, 3A, 3B, 4, 5, 5D, 17, 19, 26, 26A, 29 of 40 CFR part 60. Consistent with the NTTAA, EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods. No applicable voluntary consensus standards were identified for EPA Methods 2F, 2G, 5D, and 19. The search and review results have been documented and are placed in the docket for the proposed rule.

The three voluntary consensus standards described below were identified as acceptable alternatives to EPA test methods for the purposes of the proposed rule.

The voluntary consensus standard ASME PTC 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," is cited in the proposed rule for its manual method for measuring the oxygen, carbon dioxide, and carbon monoxide content of exhaust gas. This part of ASME PTC 19–10–1981—Part 10 is an acceptable alternative to Method 3B.

The voluntary consensus standard ASTM D6522–00, "Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers" is an acceptable alternative to EPA Method 3A for identifying carbon monoxide and oxygen concentrations for the proposed rule when the fuel is natural gas.

The voluntary consensus standard ASTM Z65907, "Standard Method for Both Speciated and Elemental Mercury Determination," is an acceptable alternative to EPA Method 29 (portion for mercury only) for the purpose of the proposed rule. This standard can be used in the proposed rule to determine the mercury concentration in stack gases for boilers with rated heat input capacities of greater than 250 MMBtu per hour.

In addition to the voluntary consensus standards EPA uses in the proposed rule, the search for emissions measurement procedures identified 15 other voluntary consensus standards. The EPA determined that 13 of these 15 standards identified for measuring emissions of the HAP or surrogates subject to emission standards in the proposed rule were impractical alternatives to EPA test methods for the purposes of the rule. Therefore, EPA does not intend to adopt these standards for this purpose. The reasons for this determination for the 13 methods are discussed below.

The voluntary consensus standard ASTM D3154–00, "Standard Method for Average Velocity in a Duct (Pitot Tube Method)," is impractical as an alternative to EPA Methods 1, 2, 3B, and 4 for the purposes of the proposed rulemaking since the standard appears to lack in quality control and quality assurance requirements. Specifically, ASTM D3154–00 does not include the following: (1) Proof that openings of standard pitot tube have not plugged during the test; (2) if differential pressure gauges other than inclined manometers (*e.g.,* magnehelic gauges) are used, their calibration must be checked after each test series; and (3) the frequency and validity range for calibration of the temperature sensors.

The voluntary consensus standard ASTM D3464–96 (2001), "Standard Test Method Average Velocity in a Duct Using a Thermal Anemometer," is impractical as an alternative to EPA Method 2 for the purposes of the proposed rule primarily because applicability specifications are not clearly defined, *e.g.,* range of gas composition, temperature limits. Also, the lack of supporting quality assurance data for the calibration procedures and specifications, and certain variability issues that are not adequately addressed by the standard limit EPA's ability to make a definitive comparison of the method in these areas.

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

The voluntary consensus standard, CAN/CSA Z223.2–M86(1999), "Method for the Continuous Measurement of Oxygen, Carbon Dioxide, Carbon Monoxide, Sulphur Dioxide, and Oxides of Nitrogen in Enclosed Combustion Flue Gas Streams," is unacceptable as a substitute for EPA Method 3A since it does not include quantitative specifications for measurement system performance, most notably the calibration procedures and instrument performance characteristics. The instrument performance characteristics that are provided are nonmandatory and also do not provide the same level of quality assurance as the EPA methods. For example, the zero and span/calibration drift is only checked weekly, whereas the EPA methods requires drift checks after each run.

Two very similar voluntary consensus standards, ASTM D5835–95 (2001), "Standard Practice for Sampling Stationary Source Emissions for Automated Determination of Gas Concentration," and ISO 10396:1993, "Stationary Source Emissions: Sampling for the Automated Determination of Gas Concentrations," are impractical alternatives to EPA Method 3A for the purposes of the proposed rule because they lack in detail and quality assurance/quality control requirements. Specifically, these two standards do not include the following: (1) Sensitivity of the method; (2) acceptable levels of analyzer calibration error; (3) acceptable levels of sampling system bias; (4) zero drift and calibration drift limits, time span, and required testing frequency; (5) a method to test the interference response of the analyzer; (6) procedures to determine the minimum sampling time per run and minimum measurement time; and (7) specifications for data recorders, in terms of resolution (all types) and recording intervals (digital and analog recorders, only).

The voluntary consensus standard ISO 12039:2001, "Stationary Source Emissions—Determination of Carbon Monoxide, Carbon Dioxide, and Oxygen—Automated Methods," is not acceptable as an alternative to EPA Method 3A. This ISO standard is similar to EPA Method 3A, but is missing some key features. In terms of sampling, the hardware required by ISO 12039:2001 does not include a 3-way calibration valve assembly or equivalent to block the sample gas flow while calibration gases are introduced. In its calibration procedures, ISO 12039:2001 only specifies a two-point calibration while EPA Method 3A specifies a three-point calibration. Also, ISO 12039:2001 does not specify performance criteria for calibration error, calibration drift, or sampling system bias tests as in the EPA method, although checks of these quality control features are required by the ISO standard.

The voluntary consensus standard ASME PTC–38–80 R85 (1985), "Determination of the Concentration of Particulate Matter in Gas Streams," is not acceptable as an alternative for EPA Method 5 because ASTM PTC–38–80 is not specific about equipment requirements, and instead presents the options available and the pro's and con's of each option. The key specific differences between ASME PTC–38–80 and the EPA methods are that the ASME standard: (1) Allows in-stack filter placement as compared to the out-of-stack filter placement in EPA Methods 5 and 17; (2) allows many different types of nozzles, pitots, and filtering equipment; (3) does not specify a filter weighing protocol or a minimum allowable filter weight fluctuation as in the EPA methods; and (4) allows filter paper to be only 99 percent efficient, as compared to the 99.95 percent efficiency required by the EPA methods.

The voluntary consensus standard ASTM D3685/D3685M–98, "Test Methods for Sampling and Determination of Particulate Matter in Stack Gases," is similar to EPA Methods 5 and 17, but is lacking in the following areas that are needed to produce quality, representative particulate data: (1) Requirement that the filter holder temperature should be between 120°C and 134°C, and not just "above the acid dew-point;" (2) detailed specifications for measuring and monitoring the filter holder temperature during sampling; (3) procedures similar to EPA Methods 1, 2, 3, and 4, that are required by EPA Method 5; (4) technical guidance for performing the Method 5 sampling procedures, *e.g.,* maintaining and monitoring sampling train operating temperatures, specific leak check guidelines and procedures, and use of reagent blanks for determining and subtracting background contamination; and (5) detailed equipment and/or operational requirements, *e.g.,* component exchange leak checks, use of glass cyclones for heavy particulate loading and/or water droplets, operating under a negative stack pressure, exchanging particulate loaded filters, sampling preparation and implementation guidance, sample recovery guidance, data reduction guidance, and particulate sample calculations input.

The voluntary consensus standard ISO 9096:1992, "Determination of Concentration and Mass Flow Rate of Particulate Matter in Gas Carrying Ducts—Manual Gravimetric Method," is not acceptable as an alternative for EPA Method 5. Although sections of ISO 9096 incorporate EPA Methods 1, 2, and 5 to some degree, this ISO standard is not equivalent to EPA Method 5 for collection of particulate matter. The standard ISO 9096 does not provide applicable technical guidance for performing many of the integral procedures specified in Methods 1, 2, and 5. Major performance and operational details are lacking or nonexistent, and detailed quality assurance/quality control guidance for the sampling operations required to produce quality, representative particulate data (*e.g.,* guidance for maintaining and monitoring train operating temperatures, specific leak check guidelines and procedures, and sample preparation and recovery procedures) are not provided by the standard, as in EPA Method 5. Also, details of equipment and/or operational requirements, such as those specified in EPA Method 5, are not included in the ISO standard, *e.g.,* stack gas moisture measurements, data reduction guidance, and particulate sample calculations.

The voluntary consensus standard CAN/CSA Z223.1–M1977, "Method for the Determination of Particulate Mass Flows in Enclosed Gas Streams," is not acceptable as an alternative for EPA Method 5. Detailed technical procedures and quality control measures that are required in EPA Methods 1, 2, 3, and 4 are not included in CAN/CSA Z223.1. Second, CAN/CSA Z223.1 does not include the EPA Method 5 filter weighing requirement to repeat weighing every 6 hours until a constant weight is achieved. Third, EPA Method 5 requires the filter weight to be reported to the nearest 0.1 mg, while CAN/CSA Z223.1 requires only to the nearest 0.5 mg. Also, CAN/CSA Z223.1 allows the use of a standard pitot for velocity measurement when plugging of the tube opening is not expected to be a problem. Whereas, EPA Method 5 requires an S-shaped pitot.

The voluntary consensus standard EN 1911–1,2,3 (1998), "Stationary Source Emissions-Manual Method of Determination of HCl—Part 1: Sampling of Gases Ratified European Text—Part 2: Gaseous Compounds Absorption Ratified European Text—Part 3: Adsorption Solutions Analysis and Calculation Ratified European Text," is impractical as an alternative to EPA Methods 26 and 26A. Part 3 of this standard cannot be considered equivalent to EPA Method 26 or 26A because the sample absorbing solution (water) would be expected to capture both HCl and chlorine gas, if present, without the ability to distinguish between the two. The EPA Methods 26 and 26A use an acidified absorbing solution to first separate HCl and chlorine gas so that they can be selectively absorbed, analyzed, and reported separately. In addition, in EN 1911 the absorption efficiency for chlorine gas would be expected to vary as the pH of the water changed during sampling.

The voluntary consensus standard EN 13211 (1998), is not acceptable as an alternative to the mercury portion of EPA Method 29 primarily because it is not validated for use with impingers, as in the EPA method, although the method describes procedures for the use of impingers. This European standard is validated for the use of fritted bubblers only and requires the use of a side (split) stream arrangement for isokinetic sampling because of the low sampling rate of the bubblers (up to 3 liters per minute, maximum). Also, only two bubblers (or impingers) are required by EN 13211, whereas EPA Method 29 require the use of six impingers. In addition, EN 13211 does not include many of the quality control procedures of EPA Method 29, especially for the use and calibration of temperature sensors and controllers, sampling train assembly and disassembly, and filter weighing.

Two of the 15 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the proposed rule because they are under development by a voluntary consensus body: ASME/BSR MFC 13M, "Flow Measurement by Velocity Traverse," for EPA Method 2 (and possibly 1); and ASME/BSR MFC 12M, "Flow in Closed Conduits Using Multiport Averaging Pitot Primary Flowmeters," for EPA Method 2.

Section 63.7520 and Tables 4A through 4D to subpart DDDDD, 40 CFR part 63, list the EPA testing methods included in the proposed rule. Under § 63.7(f) and § 63.8(f) of subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures.

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

Executive Order 13211, (66 FR 28355, May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action." The proposed rule is not a "significant regulatory action" because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for the determination is as follows.

We estimate a 0.14% price increase for the energy sector and a 0.07% percentage change in production. We estimate a 0.18% increase in energy imports. For more information on the estimated energy effects, please refer to the economic impact analysis for the proposed rule. The analysis is available in the public docket.

Therefore, we conclude that the proposed rule when implemented is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

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 environmental justice (EJ). Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice 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 United States.

This proposed action establishes national emission standards for new and existing industrial, commercial, institutional boilers and process heaters that combust non-waste materials (i.e. natural gas, process gas, fuel oil, biomass, and coal) and that are located at a major source. The EPA estimates that there are approximately 13,555 units located at 1,608 facilities covered by this rule.

The proposed rule will reduce emissions of all the listed HAP that come from boilers and process heaters. This includes metals (mercury, arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium), organics (POM, acetaldehyde, acrolein, benzene, dioxins, ethylene dichloride, formaldehyde, and PCB), hydrochloric acid, and hydrofluoric acid. Adverse health effects from these pollutants include cancer, irritation of the lungs, skin, and mucus membranes; effects on the central nervous system, damage to the kidneys, and other acute health disorders. The rule will also result in substantial reductions of criteria pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM), and sulfur dioxide (SO_2). Sulfur dioxide and NO_2 are precursors for the formation of $PM_{2.5}$ and ozone. Reducing these emissions will reduce ozone and $PM_{2.5}$ formation and associated health effects, such as adult premature mortality, chronic and acute bronchitis, asthma, and other respiratory and cardiovascular diseases. (Please refer to the RIA contained in the docket for this rulemaking.)

Pursuant to E.O. 12898 EPA has undertaken to determine the aggregate demographic makeup of the communities near affected sources. This analysis used "proximity-to-a-source" to identify the populations considered to be living near affected sources, such that they have notable exposures to current emissions from these sources. In this approach EPA reviewed the distributions of different socio-demographic groups in the locations of the expected emission reductions from this rule. The review identified those census blocks within a circular distance of 3 miles of affected sources and determined the demographic and socio-economic composition (*e.g.* race, income, education, etc) of these census blocks. The radius of 3 miles (or approximately 5 kilometers) has been used in other demographic analyses focused on areas around potential sources.[27] [28] [29] [30] In addition, air modeling experience has shown that beyond 3 miles the influence of an individual source of emissions can generally be considered to be small, both in absolute terms and relative to the influence of other sources (assuming there are other sources in the area, as is typical in urban areas).

EPA's demographic analysis showed that major source boilers are located in areas where minorities' share of the population living within a three-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.[31] Based on the fact that the rule does not allow emission increases, the EPA has determined that the proposed rule will not have disproportionately high and adverse human health or environmental effects on minority, low-income, or Tribal populations. However, to the extent that any minority, low income, or Tribal subpopulation is disproportionately impacted by the current emissions as a result of the proximity of their homes to these sources, that subpopulation also

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[27] U.S. GAO (Government Accountability Office). *Demographics of People Living Near Waste Facilities.* Washington DC: Government Printing Office; 1995.

[28] Mohai P, Saha R. "Reassessing Racial and Socio-economic Disparities in Environmental Justice Research". *Demography.* 2006;43(2): 383–399.

[29] Mennis J. "Using Geographic Information Systems to Create and Analyze Statistical Surfaces of Populations and Risk for Environmental Justice Analysis". *Social Science Quarterly,* 2002;83(1):281–297.

[30] Bullard RD, Mohai P, Wright B, Saha R, *et al. Toxic Waste and Race at Twenty 1987–2007.* United Church of Christ. March, 2007.

[31] The results of the demographic analysis are presented in "Review of Environmental Justice Impacts", April 2010, a copy of which is available in the docket.

stands to see increased environmental and health benefit from the emissions reductions called for by this rule.

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 EJ newsletters, Tribal newsletters, EJ listservs, and the Internet, including the Office of Policy, Economics, and Innovation's (OPEI) 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. In addition, state and federal permitting requirements will provide state and local governments and members of affected communities the opportunity to provide comments on the permit conditions associated with permitting the sources affected by this rulemaking.

List of Subjects in 40 CFR Part 63

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

Dated: April 29, 2010.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of the Federal Regulations is proposed to be amended as follows:

PART 63—[AMENDED]

1. The authority citation for part 63 continues to read as follows:

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

2. Part 63 is amended by revising subpart DDDDD to read as follows:

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Sec.

What This Subpart Covers

§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP as defined in § 63.2 or § 63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in § 63.7491.

§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory located at a major source as defined in § 63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source as defined in § 63.7575.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

§ 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (j) of this section are not subject to this subpart.

(a) An electric utility steam generating unit.

(b) A recovery boiler or furnace covered by 40 CFR part 63, subpart MM.

(c) A boiler or process heater that is used specifically for research and development. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by 40 CFR part 63, subpart X.

(f) An ethylene cracking furnace covered by 40 CFR part 63, subpart YY.

(g) Blast furnace stoves as described in the EPA document, entitled "National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants—Background Information for Proposed Standards," (EPA–453/R–01–005).

(h) Any boiler or process heater specifically listed as an affected source in another standard(s) under 40 CFR part 63.

(i) Temporary boilers as defined in this subpart.

(j) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by [DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER] or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than [3 YEARS AFTER DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER].

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in § 63.7545 according to the schedule in § 63.7545 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

§ 63.7499 What are the subcategories of boilers and process heaters?

(a) The subcategories of boilers and process heaters are:

(1) Pulverized coal units,

(2) Stokers designed to burn coal,

(3) Fluidized bed units designed to burn coal,

(4) Stokers designed to burn biomass,

(5) Fluidized bed units designed to burn biomass,

(6) Suspension burners/Dutch Ovens designed to burn biomass,

(7) Fuel Cells designed to burn biomass,

(8) Units designed to burn liquid fuel,

(9) Units designed to burn natural gas/refinery gas,

(10) Units designed to burn other gases, and

(11) Metal process furnaces.

(b) Each subcategory is defined in § 63.7575.

§ 63.7500 What emission limits, 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 boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. 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 United States Environmental Protection Agency (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

§ 63.7505 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. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. 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.

(c) You can demonstrate compliance with the applicable emission limit for HCl or mercury using fuel analysis if the emission rate calculated according to § 63.7530(d) is less than the applicable emission limit. Otherwise, you must demonstrate compliance for HCl or mercury using performance stack testing. You must demonstrate compliance with all other applicable limits using performance stack testing, or the continuous monitoring system (CMS) where applicable.

(d) If you demonstrate compliance with any applicable emission limit through performance stack testing, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section, you must develop, and submit to the permitting authority for approval upon request, a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before

your initial performance evaluation of your CMS.

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

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

(iii) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(i) and (ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

Testing, Fuel Analyses, and Initial Compliance Requirements

§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For affected sources that elect to demonstrate compliance with any of the emission limits of this subpart through performance stack testing, your initial compliance requirements include conducting performance stack tests according to § 63.7520 and Table 5 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, establishing operating limits according to § 63.7530 and Table 7 to this subpart, and conducting CMS performance evaluations according to § 63.7525. For affected sources that burn 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 boiler or process heater according to § 63.7521 and Table 6 to this subpart.

(b) For affected sources that elect to demonstrate compliance with the emission limits for HCl or mercury through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart.

(c) If your boiler or process heater has a heat input capacity less than 100 MMBtu per hour, your initial compliance demonstration for CO is conducting a performance stack test for CO according to Table 5 to this subpart. If your boiler or process heater has a heat input capacity of 100 MMBtu per hour or greater, your initial compliance demonstration for CO is conducting a performance evaluation of your continuous emission monitoring system for CO according to § 63.7525(a).

(d) If your boiler or process heater has a heat input capacity of 250 MMBtu per hour or greater and combusts coal, biomass, or residual oil, your initial compliance demonstration for PM is conducting a performance evaluation of your continuous emission monitoring system for PM according to § 63.7525(b).

(e) 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 § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart.

(f) If your new or reconstructed affected source commenced construction or reconstruction between June 4, 2010 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).

(g) If your new or reconstructed affected source commenced construction or reconstruction between June 4, 2010, 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.

(h) 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.

§ 63.7515 When must I conduct subsequent performance tests or fuel analyses?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, unless you follow the requirements listed in paragraphs (b) through (e) of this section. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (e) of this section.

(b) 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 75 percent of 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. 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 36 months after the previous performance test. This reduced testing option does not apply to performance stack tests for dioxin/furan. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance stack tests annually.

(c) If your boiler or process heater continues to meet the emission 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 75 percent of 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 36 months after the previous performance test. This reduced testing option does not apply to performance stack tests for dioxin/furan. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance stack tests annually.

(d) If a performance test shows emissions exceeded 75 percent of the emission limit, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 3-year period show compliance.

(e) If you are required to meet an applicable work practice standard, you must conduct annual performance tune-ups according to § 63.7520. Each annual tune-up must be conducted between 10 and 12 months after the previous tune-up.

(f) If you demonstrate compliance with the mercury or HCl based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 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 boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540.

(g) You must report the results of performance tests (stack test and fuel analyses) within 60 days after the completion of the performance tests. This report must also verify that the operating limits for your affected source have not changed or provide documentation of revised operating parameters established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

§ 63.7520 What stack tests and 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 stack test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance stack tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, 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.

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 4 hours.

(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 of appendix A to part 60 of this chapter to convert the measured particulate matter concentrations, the measured HCl concentrations, and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates using F-factors.

§ 63.7521 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.

(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 boiler or process heater.

(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 or mercury.

(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 (mercury and/or chlorine) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart.

§ 63.7522 Can I use emission averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500 for particulate matter, HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategory located at your facility, you may demonstrate compliance by emission averaging, if your averaged emissions are within 90 percent of the applicable emission limit, according to the procedures in this section.

(b) Separate stack requirements. For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average particulate matter, HCl, and mercury 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 boiler or process heater 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 boilers and process heaters 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 § 63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section.

(1) You must use Equation 1 of this section to demonstrate that the particulate matter, HCl, and mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits in Table 2 to this subpart.

$$AveWeightedEmissions = 0.90 \times \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq. 1)}$$

Where:

Ave Weighted Emissions = Average weighted emissions for particulate matter, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as calculated according to Table 5 to this subpart for particulate matter, HCl, or mercury or by fuel analysis for HCl or mercury as calculated by the applicable equation in § 63.7530(c)) for unit, i, for particulate matter, HCl, or mercury, in units of pounds per million Btu 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.

0.90 = Required discount factor.

(2) If you are not capable of monitoring heat input, and the boiler generates steam, you may use Equation 2 of this section as an alternative to using Equation 1 of this section to demonstrate that the particulate matter, HCl, and mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits in Table 2 to this subpart.

$$AveWeightedEmissions = 0.90 \times \sum_{i=1}^{n} (Er \times Sm \times Cfi) \div \sum_{i=1}^{n} Sm \times Cfi \qquad \text{(Eq. 2)}$$

Where:

Ave Weighted Emissions = Average weighted emission level for PM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as calculated according to Table 5 to this subpart for particulate matter, HCl, or mercury or by fuel analysis for HCl or mercury as calculated by the applicable equation in § 63.7530(c)) for unit, i, for particulate matter, HCl, or mercury, in units of pounds per million Btu 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.

0.90 = Required discount factor.

(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 § 63.7495.

(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.

$$AveWeightedEmissions = 0.90 \times \sum_{i=1}^{n} (Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3)}$$

Where:

Ave Weighted Emissions = monthly average weighted emission level for particulate matter, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate, (as calculated during the most recent compliance test, (as calculated according to Table 5 to this subpart for particulate matter, HCl, or mercury or by fuel analysis for HCl or mercury as calculated by the applicable equation in § 63.7530(c)) for unit, i, for particulate matter, HCl, or mercury, in units of pounds per million Btu of heat input.

Hb = The average heat input for each calendar month of boiler, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

0.90 = Required discount factor.

(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.

$$AveWeightedEmissions = 0.90 \times \sum_{i=1}^{n} (Er \times Sa \times Cfi) \div \sum_{i=1}^{n} Sa \times Cfi \qquad \text{(Eq. 4)}$$

Where:

Ave Weighted Emissions = monthly average weighted emission level for PM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate, (as calculated during the most recent compliance test (as calculated according to Table 5 to this subpart for particulate matter, HCl, or mercury or by fuel analysis for HCl or mercury as calculated by the applicable equation in § 63.7530(c)) for unit, i, for particulate matter, HCl, or mercury, in units of pounds per million Btu of heat input.

Sa = Actual steam generation for each calendar month by boiler, 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.

0.90 = Required discount factor.

(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.

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \qquad \text{(Eq. 5)}$$

Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)

ERi = Monthly weighted average, for month "i", (pounds per million Btu 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).

(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 boilers and process heaters 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 boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of particulate matter, HCl, or mercury emissions in accordance with the requirements in § 63.7520;

(v) The operating parameters to be monitored for each control system or device consistent with 63.7500 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 § 63.7525, 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 particulate matter, HCl and mercury 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 § 63.7520 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.

$$En = \sum_{i=1}^{n} (ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

Where:

E_n = HAP emission limit, lb/MMBtu, ppm, or ng/dscm;

EL_i = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu, ppm or ng/dscm;

H_i = Heat input from unit i, MMBtu;

(2) Conduct performance tests according to procedures specified in § 63.7520 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); and

(3) Meet the applicable operating limit specified in § 63.7540 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 boilers or process heaters in the same subcategory subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater has a heat input capacity of 100 MMBtu per hour or greater, you must install, operate, and maintain a continuous emission monitoring system (CEMS) for CO and oxygen according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in § 63.7495. The CO and oxygen shall be monitored at the same location at the outlet of the boiler or process heater.

(1) Each CEMS must be installed, operated, and maintained according to the applicable procedures under Performance Specification (PS) 3 or 4A of 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to § 63.7505(d).

(2) You must conduct a performance evaluation of each CEMS according to the requirements in § 63.8 and according to PS 4A of 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2).

(5) You must calculate and record a 30-day rolling average emission rate on a daily basis. A new 30-day rolling average emission rate is calculated as the average of all of the hourly CO emission data for the preceding 30 operating days.

(6) For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(b) If your boiler or process heater has a heat input capacity of 250 MMBtu per hour or greater and combusts coal, biomass, or residual oil, you must install, certify, maintain, and operate a CEMS measuring PM emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (b)(6) of this section.

(1) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(8).

(2) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of a new unit or within 180 days of the compliance date for an existing unit, as specified under § 63.7495 of this subpart.

(3) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19 of appendix A of 40 CFR part 60.

(4) Obtain valid CEMS hourly averages for all operating hours on a 30-day rolling average basis. At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(5) The 1-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler operating day daily arithmetic average emissions.

(6) 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 or EPA Reference Method 19 of appendix A of 40 CFR part 60 to provide, as necessary, valid emissions data for all operating hours per 30-day rolling average.

(c) If you have an applicable opacity operating limit, you must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

(1) Each COMS must be installed, operated, and maintained according to PS 1 of 40 CFR part 60, appendix B.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8 and according to PS 1 of 40 CFR part 60, appendix B.

(3) As specified in § 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in § 63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and 1-hour block

averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.

(1) The CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(3) For purposes of calculating data averages, you must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. You must use all the data collected during all other periods in assessing compliance. Any 15-minute period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(4) You must determine the 3-hour block average of all recorded readings, except as provided in paragraph (c)(3) of this section.

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow measurement device, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must locate the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of 2 percent of the flow rate.

(3) You must reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow sensor calibration check at least semiannually.

(f) If you have an operating limit that requires the use of a pressure measurement device, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure.

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.

(3) Use a gauge with a minimum tolerance of 1.27 centimeters of water or a transducer with a minimum tolerance of 1 percent of the pressure range.

(4) Check pressure tap pluggage daily.

(5) Using a manometer, you must check gauge calibration quarterly and transducer calibration monthly.

(6) Conduct calibration checks any time the sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(g) If you have an operating limit that requires the use of a pH measurement device, you must meet the requirements in paragraphs (d) and (g)(1) through (3) of this section.

(1) Locate the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Check the pH meter's calibration on at least two points every 8 hours of process operation.

(h) If you have an operating limit that requires the use of equipment to monitor voltage and secondary amperage (or total power input) of an electrostatic precipitator (ESP), you must use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP.

(i) If you have an operating limit that requires the use of equipment to monitor sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (c) and (i)(1) through (3) of this section.

(1) Locate the device in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Install and calibrate the device in accordance with manufacturer's procedures and specifications.

(3) At least annually, calibrate the device in accordance with the manufacturer's procedures and specifications.

(j) If you elect to use 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 paragraphs (j)(1) through (8) of this section.

(1) You must install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA–454/R–98–015, September 1997.

(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(6) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.

(7) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

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

§ 63.7530 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 (performance stack tests and fuel analyses) and establishing operating limits, as applicable, according to § 63.7520, paragraph (c) of this section, and Tables 5 and 7 to this subpart.

(b) If you demonstrate compliance through performance stack testing, you must establish each site-specific operating limit in Table 2 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (c)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (3) 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 boiler or process heater 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.

$$Clinpunt = \sum_{i=1}^{n} (Ci \times Qi) \qquad \text{(Eq. 7)}$$

Where:

Cl_{input} = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

C_i = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Q_i = 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 Q_i.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury 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 boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, 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 mercury, and the average mercury concentration of each fuel type burned (HG_i).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \qquad \text{(Eq. 8)}$$

Where:

$Mercury_{input}$ = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HG_i = Arithmetic average concentration of mercury in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Q_i = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury 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 Q_i.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(3) You must establish parameter operating limits according to paragraphs (c)(4)(i) through (iv) of this section.

(i) For a wet scrubber, you must establish the minimum scrubber effluent pH, liquid flowrate, and pressure drop as defined in § 63.7575, as your operating limits during the three-run performance test. If you use a wet scrubber and you conduct separate performance tests for particulate matter, HCl, and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flowrate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flowrate and pressure drop operating limits at the highest minimum values established during the performance tests.

(ii) For an electrostatic precipitator, you must establish the minimum voltage and secondary current (or total power input), as defined in § 63.7575, as your operating limits during the three-run performance test.

(iii) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test.

(iv) The operating limit for boilers or process heaters 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 § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the 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 § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater 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 9 of this section.

$$P90 = mean + (SD \times t) \qquad \text{(Eq. 9)}$$

Where:

P_{90} = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

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 boiler or process heater using Equation 10 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} (C90i \times Qi \times 1.028) \qquad \text{(Eq. 10)}$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

C_{i90} = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

Q_i= 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 Q_i.

n = Number of different fuel types burned in your boiler or process heater 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 mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 11 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} (HG90i \times Qi) \qquad \text{(Eq. 11)}$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

HG_{i90} = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

Q_i = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury 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 Q_i.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(d) If you own or operate an existing unit with a heat input capacity of 10 million Btu per hour or less, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

(e) You must submit the energy assessment report, along with a signed certification that the assessment is an accurate depiction of your facility.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).

Continuous Compliance Requirements

§ 63.7535 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 § 63.7505(d).

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

§ 63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 3 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) 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 63.7510, 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 times. 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 § 63.7550(c), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would either result in lower emissions of HCl and mercury, than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel input of chlorine and mercury 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 emission limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the HCl emission rate using Equation 9 of § 63.7530 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 pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 9 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission 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 5 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 5 of § 63.7530 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 § 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(c).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 11 of § 63.7530 according to the procedures specified in paragraphs (a)(7)(i) through (iii) of this section.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 11 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission 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 mercury input using Equation 7 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 7 of § 63.7530 are higher than the maximum mercury 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 § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(c).

(7) 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 alarm does not sound more than 5 percent of the 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.

(8) If you are required to install a CEMS according to § 63.7525(a), then you must meet the requirements in paragraphs (a)(8)(i) through (iii) of this section.

(i) You must continuously monitor CO according to §§ 63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable CO standard in Tables 1 or 2 to this subpart at all times.

(iii) Keep records of CO levels according to § 63.7555(b).

(9) 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)(9)(i) through (a)(9)(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 O2 (or CO2) 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 5B of appendix A–3 of 40 CFR part 60 or Method 17 of appendix A–6 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 40 CFR part 60. Relative Response Audits must be performed annually and Response Correlation Audits must be performed every 3 years.

(iv) After December 31, 2011, within 60 days after the date of completing each performance evaluation conducted to demonstrate compliance with this subpart, the owner or operator of the affected facility must submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE database through EPA's Central Data Exchange. The owner or operator of an affected facility shall enter the test data into EPA's data base using the Electronic Reporting Tool (ERT) or other compatible electronic spreadsheet.

(10) If your boiler or process heater is in either the Gas 1 (NG/RG) or Metal Process Furnace subcategories and have a heat input capacity of 10 million Btu per hour or greater, you must conduct a tune-up of the boiler or process heater annually to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section.

(i) Inspect the burner, and clean or replace any components of the burner as necessary;

(ii) Inspect the flame pattern and make any adjustments to the burner necessary to optimize the flame pattern consistent with the manufacturer's specifications;

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

(iv) Minimize total emissions of CO consistent with the manufacturer's specifications;

(v) Measure the concentration in the effluent stream of CO in parts per million, by volume, dry basis (ppmvd), 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)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in ppmvd, and oxygen in percent dry basis, measured before and after the adjustments of the boiler;

(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 the annual adjustment.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour, you must conduct a tune-up of the boiler or process heater biennially to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section.

(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 § 63.7550.

§ 63.7541 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 (5) 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 § 63.7522(f) and (g);

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) through (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from nonaffected units, maintain opacity at or below the applicable limit at the common stack;

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test; and

(4) 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.

(5) 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 (5) of this section is a deviation.

Notification, Reports, and Records

§ 63.7545 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 § 63.7530(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 (9) of this section, 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 (stack tests and fuel analyses) and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) A summary of the CO emissions monitoring data and the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Table 1 or 2 to this subpart.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance stack testing or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging.

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) 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.

(f) If you operate a natural gas-fired boiler or process heater that is subject to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

§ 63.7550 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 § 63.7495 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 § 63.7495.

(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 § 63.7495.

(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 § 63.7515(b) or (c), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 90 percent emission limit threshold required in § 63.7515(b) or (c), 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 5 of § 63.7530, 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 9 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of mercury input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 11 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters 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 5 of § 63.7530 or the maximum mercury input operating limit using Equation 7 of § 63.7530, 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, COMS, 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.

(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 § 63.7505(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 § 63.7540(a)(10) to conduct an annual tune-up of the unit".

(2) "This facility has had an energy assessment performed according to § 63.7530(e)."

(3) "No secondary materials that are solid waste were combusted in any affected unit."

(h) After December 31, 2011, within 60 days after the date of completing each performance evaluation conducted to demonstrate compliance with this subpart, the owner or operator of the affected facility must submit the test data to EPA by entering the data electronically into EPA's WebFIRE data base through EPA's Central Data Exchange. The owner or operator of an affected facility shall enter the test data into EPA's data base using the Electronic Reporting Tool or other compatible electronic spreadsheet. Only performance evaluation data collected using methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

§ 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (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, performance evaluations, and opacity observations as required in § 63.10(b)(2)(viii).

(b) For each CEMS, CPMS, and COMS, you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in § 63.6(h)(7)(i) and (ii).

(3) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(5) 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 opacity, pressure drop, and pH to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater 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 boiler or process heater, 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 41.3(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) You must keep records of monthly hours of operation by each boiler or process heater. This requirement applies only to limited-use boilers and process heaters.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 5 of § 63.7530, 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 9 of § 63.7530, 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 boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the mercury 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 mercury emission rates, using Equation 11 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(6) If consistent with § 63.7555(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 relevant pollutant to increase within the past year.

(7) If you operate a gaseous fuel unit that is subject to the emission limits specified in Table 1 or 2 to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must keep records of the information required by the notification under § 63.7550, and records of the total hours per calendar year that liquid fuel is burned.

(e) If you elect to average emissions consistent with § 63.7522, you must additionally keep a copy of the emission averaging implementation plan required in § 63.7522(g), all calculations required under § 63.7522, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.7541.

§ 63.7560 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

§ 63.7565 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.

§ 63.7570 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 (5) 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 § 63.7500(a) and (b) under § 63.6(g).

(2) Approval of alternative opacity emission limits in § 63.7500(a) under § 63.6(h)(9).

(3) 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, and alternative analytical methods requested under 63.7521(b)(2).

(4) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under 63.7500(a)(2) and 63.7522(g)(2).

(5) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

§ 63.7575 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:

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter 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 particulate matter loadings.

Biomass fuel means but is not limited to, wood residue, and wood products (*e.g.,* trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.,* almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass fuel is not intended to suggest that these materials are or are not solid waste.

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total heat input (based on an annual average) from blast furnace gas.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. A device combusting solid waste, as defined in 40 CFR 241.3, is not a boiler. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feedwater system, the combustion air system, the fuel system (including burners), blowdown system, combustion control system, and energy consuming systems.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388–991.[1], "Standard Specification for Classification of Coals by Rank" [1] (incorporated by reference, *see* § 63.14(b)), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat including, but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures, for the purposes of this subpart. Coal derived gases are excluded from this definition.

Coal refuse means any by-product of coal mining or coal cleaning operations 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.

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue.

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of two years or less.

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, or work practice standard; 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. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D396–02a, "Standard Specifications for Fuel Oils" [1] (incorporated by reference, *see* § 63.14(b)).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems in fluidized bed boilers and process heaters are included in this definition.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the Dutch oven and burn in a pile on its floor.

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

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

Energy assessment means an in-depth assessment of a facility to identify immediate and long-term opportunities to save energy, focusing on the steam and process heating systems which involves a thorough examination of potential savings from energy efficiency improvements, waste minimization and pollution prevention, and productivity improvement.

Equivalent means the following only as this term is used in Table 6 to subpart DDDDD:

(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 mercury, 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 (mercury) 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 to or lower than the methods listed in Table 6 to subpart DDDDD for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse.

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

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 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.

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater 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, kilns, etc.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210 °F (99 °C).

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Liquid fuel includes, but is not limited to, distillate oil, residual oil, on-spec used oil, and biodiesel.

Liquid fuel subcategory includes any boiler or process heater of any design that burns more than 10 percent liquid fuel and less than 10 percent solid fuel, on an annual heat input basis.

Metal process furnaces include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, and heat treat furnaces.

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 hydrogen chloride 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 the American Society for Testing and Materials in ASTM D1835–03a, "Standard Specification for Liquid Petroleum Gases" (incorporated by reference, *see* § 63.14(b)).

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Particulate matter 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.

Period of natural gas curtailment or supply interruption means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.

Process heater means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. A device combusting solid waste, as defined in 40 CFR 241.3, is not a process heater. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.

Pulverized coal boiler means a boiler in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

Qualified personnel means specialists in evaluating energy systems, such as those who have successfully completed the DOE Qualified Specialist program for all systems, Certified Energy Manager certified by the Association of Energy Engineers, or the equivalent.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by the American Society for Testing and Materials in ASTM D396–02a, "Standard Specifications for Fuel Oils [1]" (incorporated by reference, *see* § 63.14(b)).

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

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.

Suspension boiler means a unit designed to feed the fuel by means of fuel distributors. The distributors inject air at the point where the fuel is introduced into the boiler in order to spread the fuel material over the boiler width. The drying (and much of the combustion) occurs while the material is suspended in air. The combustion of the fuel material is completed on a grate or floor below. Suspension boilers almost universally are designed to have high heat release rates to quickly dry the wet fuel as it is blown into the boilers.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period.

Tune-up means adjustments made to a boiler in accordance with procedures supplied by the manufacturer (or an approved specialist) to optimize the combustion efficiency.

Unit designed to burn biomass subcategory includes any boiler or process heater that burns at least 10 percent biomass, but less than 10 percent coal, on a heat input basis on an annual average, either alone or in combination with liquid fuels or gaseous fuels.

Unit designed to burn coal subcategory includes any boiler or process heater that burns any coal alone or at least 10 percent coal on a heat input basis on an annual average in combination with biomass, liquid fuels, or gaseous fuels.

Unit designed to burn gas 1 (NG/RG) subcategory includes any boiler or process heater that burns at least 90 percent natural gas and/or refinery gas on a heat input basis on an annual average.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that burns gaseous fuels other than natural gas and/or refinery gas not combined with any solid or liquid fuels.

Unit designed to burn oil subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent solid fuel on a heat input basis on an annual average, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included in this definition.

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.

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat recovery boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.

Waste heat process heater means an enclosed device that recovers normally unused energy and converts it to usable heat. Waste heat process heaters incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat process heater are not considered waste heat process heaters, but are considered process heaters. Waste heat process heaters are also referred to as recuperative process heaters.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter and/or to absorb and neutralize acid gases, such as hydrogen chloride.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.

Tables to Subpart DDDDD of Part 63

As stated in § 63.7500, you must comply with the following applicable emission limits:

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .
1. Pulverized coal	a. Particulate Matter	0.001 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.00006 lb per MMBtu of heat input.
	c. Mercury	2.0E–06 lb per MMBtu of heat input.
	d. CO	90 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.
2. Stokers designed to burn coal	a. Particulate Matter	0.001 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.00006 lb per MMBtu of heat input.
	c. Mercury	2.0E–06 lb per MMBtu of heat input.
	d. CO	7 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.
3. Fluidized bed units designed to burn coal.	a. Particulate Matter	0.001 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.00006 lb per MMBtu of heat input.
	c. Mercury	2.0E–06 lb per MMBtu of heat input.
	d. CO	30 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.00003 ng/dscm (TEQ) corrected to 7 percent oxygen.
4. Stokers designed to burn biomass.	a. Particulate Matter	0.008 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.004 lb per MMBtu of heat input.
	c. Mercury	2.0E–07 lb per MMBtu of heat input.
	d. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.00005 ng/dscm (TEQ) corrected to 7 percent oxygen.
5. Fluidized bed units designed to burn biomass.	a. Particulate Matter	0.008 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.004 lb per MMBtu of heat input.
	c. Mercury	2.0E–07 lb per MMBtu of heat input.
	d. CO	40 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.007 ng/dscm (TEQ) corrected to 7 percent oxygen.
6. Suspension burners/Dutch Ovens designed to burn biomass.	a. Particulate Matter	0.008 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.004 lb per MMBtu of heat input.
	c. Mercury	2.0E–07 lb per MMBtu of heat input.
	d. CO	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.03 ng/dscm (TEQ) corrected to 7 percent oxygen.
7. Fuel cells designed to burn biomass.	a. Particulate Matter	0.008 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.004 lb per MMBtu of heat input.
	c. Mercury	2.0E–07 lb per MMBtu of heat input.
	d. CO	270 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.0005 ng/dscm (TEQ) corrected to 7 percent oxygen.
8. Units designed to burn liquid fuel	a. Particulate Matter	0.002 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0004 lb per MMBtu of heat input.
	c. Mercury	3.0E–07 lb per MMBtu of heat input.
	d. CO	1 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .
9. Units designed to burn other gases.	a. Particulate Matter	0.003 lb per MMBtu of heat input.
	b. Hydrogen Chloride	3.0E–06 lb per MMBtu of heat input.
	c. Mercury	2.0E–07 lb per MMBtu of heat input.
	d. CO	1 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.009 ng/dscm (TEQ) corrected to 7 percent oxygen.

As stated in § 63.7500, you must comply with the following applicable emission limits:

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .
1. Pulverized coal	a. Particulate Matter	0.02 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	3.0E–06 lb per MMBtu of heat input.
	d. CO	90 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.004 ng/dscm (TEQ) corrected to 7 percent oxygen.
2. Stokers designed to burn coal	a. Particulate Matter	0.02 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	3.0E–06 lb per MMBtu of heat input.
	d. CO	50 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.
3. Fluidized bed units designed to burn coal.	a. Particulate Matter	0.02 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	3.0E–06 lb per MMBtu of heat input.
	d. CO	30 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.
4. Stokers designed to burn biomass.	a. Particulate Matter	0.02 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.006 lb per MMBtu of heat input.
	c. Mercury	9.0E–07 lb per MMBtu of heat input.
	d. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.004 ng/dscm (TEQ) corrected to 7 percent oxygen.
5. Fluidized bed units designed to burn biomass.	a. Particulate Matter	0.02 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.006 lb per MMBtu of heat input.
	c. Mercury	9.0E–07 lb per MMBtu of heat input.
	d. CO	250 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen.
6. Suspension burners/Dutch Ovens designed to burn biomass.	a. Particulate Matter	0.02 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.006 lb per MMBtu of heat input.
	c. Mercury	9.0E–07 lb per MMBtu of heat input.
	d. CO	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.03 ng/dscm (TEQ) corrected to 7 percent oxygen.
7. Fuel cells designed to burn biomass.	a. Particulate Matter	0.02 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.006 lb per MMBtu of heat input.
	c. Mercury	9.0E–07 lb per MMBtu of heat input.
	d. CO	270 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .
8. Units designed to burn liquid fuel	a. Particulate Matter	0.004 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0009 lb per MMBtu of heat input.
	c. Mercury	4.0E–06 lb per MMBtu of heat input.
	d. CO	1 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.
9. Units designed to burn other gases.	a. Particulate Matter	0.05 lb per MMBtu of heat input.
	b. Hydrogen Chloride	3.0E–06 lb per MMBtu of heat input.
	c. Mercury	2.0E–07 lb per MMBtu of heat input.
	d. CO	1 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
	e. Dioxin/Furan	0.009 ng/dscm (TEQ) corrected to 7 percent oxygen.

As stated in §§ 63.11202 and 63.11203, you must comply with the following applicable work practice standards:

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS

If your boiler is . . .	You must meet the following . . .
1. An existing boiler or process heater with heat input capacity of less than 10 million Btu per hour.	Conduct a tune-up of the boiler biennially as specified in § 63.7540.
2. A new or existing boiler or process heater in either the Gas 1 or Metal Process Furnace subcategory with heat input capacity of 10 million Btu per hour or greater.	Conduct a tune-up of the boiler annually as specified in § 63.7540.
3. An existing boiler located at a major source facility.	Must have an energy assessment performed on the major source facility by qualified personnel which includes: (a) a visual inspection of the boiler system. (b) establish operating characteristics of the facility, energy system specifications, operating and maintenance procedures, and unusual operating constraints, (c) identify major energy consuming systems, (d) a review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage, (e) a list of major energy conservation measures, (f) the energy savings potential of the energy conservation measures identified, and (g) a comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments, and (h) a facility energy management program developed according to the ENERGY STAR guideline for energy management.

As stated in § 63.7500, you must comply with the applicable operating limits:

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS

If you demonstrate compliance using . . .	You must meet these operating limits . . .
1. Wet scrubber control	a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart.
2. Fabric filter control	a. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period; or
	b. This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent (daily block average).
3. Electrostatic precipitator control	a. This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS—Continued

If you demonstrate compliance using . . .	You must meet these operating limits . . .
	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(c) and Table 7 to this subpart.
4. Dry scrubber or carbon injection control	Maintain the minimum sorbent or carbon injection rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart.
5. Any other control type	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(d)(3), (4) and/or (5) is less than the applicable emission limits.

As stated in § 63.7520, you must comply with the following requirements for performance test for existing, new or reconstructed affected sources:

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
2. Hydrogen chloride	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the hydrogen chloride emission concentration.	Method 26 or 26A in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
3. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 62.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the mercury emission concentration.	Method 29 in appendix A to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784–02 (IBR, see § 63.14(b)).
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
4. CO	a. Select the sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)), or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	c. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	d. Measure the CO emission concentration.	Method 10 in appendix A to part 60 of this chapter.
5. Dioxin/Furan	a. Select the sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
	b. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)), or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	c. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	d. Measure the dioxin/furans emission concentration.	Method __ in appendix A to part 60 of this chapter.

As stated in § 63.7521, 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 DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234–D2234M–03 (for coal) (IBR, see § 63.14(b)) or ASTM D6323–98 (2003) (for biomass) (IBR, See § 63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW–846–3020A (for liquid samples) or ASTM D2013–04 (for coal) (IBR, see § 63.14(b)) or ASTM D5198–92 (2003) (for biomass) (IBR, see § 63.14(b)) or equivalent.
	d. Determine heat content of the fuel type.	ASTM D5865–04 (for coal) (IBR, see § 63.24(b)) or ASTM E711–87 (for biomass) (IBR, see § 63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type.	ASTM D3173–03 (IBR, see § 63.14(b)) or ASTM E871–82 (1998) (IBR, see § 63.14(b)) or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D6722–01 (for coal) (IBR, see § 6314(b)) 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 MMBtu of heat content.	
2. Hydrogen Chloride	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234–D2234M–03 (for coal) (IBR, see § 63.14(b)) or ASTM D6323–98 (2003) (for biomass) (IBR, see § 63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW–846–3020A (for liquid samples) or ASTM D2013–04 (for coal) (IBR, see § 63.14(b)) or ASTM D5198–92 (2003) (for biomass) (IBR, see § 63.14(b)) or equivalent.
	d. Determine heat content of the fuel type * * *.	ASTM D5865–04 (for coal) (IBR, see § 63.14(b)) or ASTM E711–87 (1996) (for biomass) (IBR, see § 63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type.	ASTM D3173–03 (IBR, see § 63.14(b)) or ASTM E871–82 (1998) or equivalent.
	f. Measure chlorine concentration in fuel sample.	SW–846–9250 or ASTM D6721–01 (for coal) or ASTM E776–87 (1996) (for biomass) (IBR, see § 63.14(b)) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

TABLE 7 TO SUBPART DDDDD 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 or mercury.	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(c).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter or mercury 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 pressure drop and liquid flow-rate 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 with additional wet scrubber control).	i. Establish a site-specific minimum voltage and secondary current or total power input according to § 63.7530(c).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter or mercury performance test.	(a) You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests; (b) Determine the average voltage and secondary current or total power input 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.
2. Hydrogen Chloride	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(c).	(1) Data from the pH, pressure drop, and liquid flow-rate monitors and the hydrogen chloride performance test.	(a) You must collect pH, pressure drop, and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average pH, pressure drop, and liquid flow-rate 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 operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(c).	(1) Data from the sorbent injection rate monitors and hydrogen chloride 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 sorbent injection rate 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.

As stated in § 63.7540, you must show continuous compliance with the emission limitations for affected sources according to the following:

TABLE 8 TO SUBPART DDDDD 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. Opacity	a. Collecting the opacity monitoring system data according to §§ 63.7525(b) and 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(9) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow-rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; 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 § 63.7530(c).
4. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average pH at or above the operating limit established during the performance test according to § 63.7530(c).
5. Dry Scrubber Sorbent or Carbon Injection Rate.	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; 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 §§ 63.7530(c).
6. Electrostatic Precipitator Secondary Current and Voltage or Total Power Input.	a. Collecting the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average secondary current and voltage or total power input at or above the operating limits established during the performance test according to §§ 63.7530(c).
7. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.7530(c) or (d) as applicable; and b. Keeping monthly records of fuel use according to § 63.7540(a).

As stated in § 63.7550, you must comply with the following requirements for reports:

TABLE 9 TO SUBPART DDDDD 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 § 63.7550(c)(1) 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, continuous opacity 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	Semiannually according to the requirements in § 63.7550(b).

TABLE 9 TO SUBPART DDDDD OF PART 63—REPORTING REQUIREMENTS—Continued

You must submit a(n) . . .	The report must contain . . .	You must submit the report . . .
	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 § 63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity 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 § 63.7550(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).	
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 relevant emission standard.	a. Actions taken for the event; and b. The information in § 63.10(d)(5)(ii)	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and 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 § 63.7565, you must comply with the applicable General Provisions according to the following:

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD

Citation	Subject	Applies to subpart DDDDD
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575.
§ 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), (e)(3), (f)(1), and (h)(1)	Startup, shutdown, and malfunction requirements and Opacity/Visible Emission Limits.	No. Standards apply at all times, including during startup, shutdown, and malfunction events.
§ 63.7(a), (b), (c), (d), (e)(2)–(e)(9), (f), (g), and (h).	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Conditions for conducting performance tests.	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520.
§ 63.8	Monitoring Requirements	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1), (b)(2)(i)–(iii), (b)(2)(vi)–(xiv), (c), (d)(1)–(2), (e), and (f).	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(iv)–(v), (b)(3), and (d)(3)–(5)	....	No.
§ 63.10(c)(15)	Allows use of SSM plan	No.
§ 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.

[FR Doc. 2010–10827 Filed 6–3–10; 8:45 am]

BILLING CODE 6560–50–P