

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA-HQ-OAR-2002-0058; FRL-9272-8]

RIN 2060-AQ25

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final 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 standards.

In response to the Court's vacatur and remand, EPA is, in this action, establishing emission standards that will require industrial/commercial/institutional boilers and process heaters located at major sources to meet hazardous air pollutants standards reflecting the application of the maximum achievable control technology. This rule protects air quality and promotes public health by reducing emissions of the hazardous air pollutants listed in section 112(b)(1) of the Clean Air Act.

DATES: This final rule is effective on May 20, 2011. The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of May 20, 2011.

ADDRESSES: EPA established a single docket under Docket ID No. EPA-HQ-OAR-2002-0058 for this action. All documents in the docket are listed on the <http://www.regulations.gov> Web site. Although listed in the index, some information is not publicly available, e.g., confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either

electronically through <http://www.regulations.gov> or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. This Docket Facility 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) 566-1741.

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.

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I. General Information

A. Does this action apply to me?

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

Category	NAICS code ¹	Examples of potentially regulated entities
Any industry using a boiler or process heater as defined in the final rule.	211	Extractors of crude petroleum and natural gas.

Category	NAICS code ¹	Examples of potentially regulated entities
	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. Where can I get a copy of this document?

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

C. Judicial Review

Under the Clean Air Act (CAA) section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by May 20, 2011. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. This section also provides a mechanism for us to convene a proceeding for reconsideration, “[i]f the person raising an objection can demonstrate to EPA that it was

impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of this rule.” Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

II. Background Information

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

Section 112(d) of the 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.

With respect to alkylated lead compounds; polycyclic organic matter (POM); hexachlorobenzene; mercury (Hg); polychlorinated biphenyls; 2,3,7,8-tetrachlorodibenzofurans; and 2,3,7,8-tetrachlorodibenzo-p-dioxin, the 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 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 POM and Hg (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 (D.C. 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 CISWI definitions 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. A more detailed discussion of this decision, as well as other court decisions relevant to today’s action, can be found in the June 4, 2010, preamble to the proposed rule. See 75 FR 32009.

CAA section 129 covers any facility that combusts any solid waste; CAA section 129(g)(6) directs the Agency to the Resource Conservation and Recovery Act (RCRA) in terms of the definition of solid waste. In this **Federal Register**, EPA is issuing a definition of solid waste for purposes 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 finalized 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 combust secondary materials that are solid waste under the final definitional rule, those units would be subject to emission standards issued under section 129. The units subject to this final rule include those industrial, commercial, or institutional boilers and process heaters that do not combust solid waste, as well as boilers and process heaters that combust solid waste but qualify for one of the statutory exclusions contained in section 129(g)(1). 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 used the information currently available to the Agency to determine which units combust solid waste materials and, therefore, are subject to CAA section 129, and which units do not combust solid waste (or qualify for an exclusion from section 129) and, therefore, are subject to CAA section 112.

B. EPA’s Response to the Vacatur

A description of EPA’s information collection efforts and a description of the development of EPA’s proposed response to the *NRDC v. EPA* mandate is contained in the preamble to the proposed rule. See 75 FR 32010–32011. After consideration of public comments on the proposed rule, we have made appropriate revisions to the final rule, and a description of the major changes is provided in this preamble. The changes reflect EPA’s consideration of public comments and the consideration of additional information and emissions data provided through the public comment process. The changes also reflect adjustments to the definition of non-hazardous solid waste as set forth in a parallel final action. That final rule contains some revisions to the definition of non-hazardous solid waste proposed by EPA in June 2010. Accordingly, 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) were established considering the final solid waste definition issued today. We used the updated inventories and all available data, as appropriate, to develop the final standards for boilers and process heaters under CAA section 112 and, in a separate parallel action, the final standards for commercial and industrial solid waste incineration units covered by CAA section 129. We used all of the appropriate information

available to the Administrator to calculate the MACT floors, set emission limits, and evaluate the emission impacts of various regulatory options for these final rulemakings.

C. What is the relationship between this final rule and other combustion rules?

This final rule addresses the combustion of non-solid waste materials in boilers and process heaters located at major sources of HAP. If an owner or operator of an affected source subject to these 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 finalized in a parallel action and is relevant to this action because it would apply to boilers and process heaters that combust any solid waste and are located at a major source. In this final boiler rulemaking, EPA is providing specific language to ensure clarity regarding the necessary steps that must be followed for combustion units that begin combusting non-hazardous solid waste materials and become subject to section 129 standards instead of section 112 standards or combustion units that discontinue combustion of non-hazardous solid waste materials and become subject to section 112 standards instead of section 129 standards.

In addition to combustion units that may switch between the section 112 boiler standards and the section 129 incinerator standards, there are certain instances where boilers and process heaters are already regulated under other MACT standards. In such cases, the boilers and process heaters that are already subject to another MACT standard are not subject to the boiler standards.

In 1986, EPA codified new source performance standards (NSPS) for industrial boilers (40 CFR part 60, subparts Db and Dc) and portions of those standards were revised in 1999 and 2006. The NSPS regulates emissions of particulate matter (PM), sulfur dioxide (SO₂), and nitrogen oxide (NO_x) from boilers constructed after June 19, 1984. Sources subject to the NSPS will also be subject to the final CAA section 112(d) standards for boilers and process heaters because the section 112(d) standards regulate HAP emissions while the NSPS do not. However, in developing this final rule, we considered the monitoring requirements, testing requirements, and recordkeeping requirements of the NSPS to avoid duplicating requirements.

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

This final 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 rule show that hydrogen chloride (HCl) emissions represent the predominant HAP emitted by industrial, commercial, and institutional (ICI) boilers, accounting for 69 percent of the total HAP emissions.¹ ICI boilers and process heaters also emit lesser amounts of hydrogen fluoride, accounting for about 21 percent of total

HAP emissions, and metals (arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese (Mn), Hg, nickel, and selenium) accounting for about 6 percent of total HAP emissions. Organic HAP (formaldehyde, POM, acetaldehyde, benzene) account for about 4 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 final rule would reduce emissions and subsequent exposures.

E. What are the costs and benefits of this final rule?

EPA estimated the costs and benefits associated with the final rule, and the results are shown in the following table. For more information on the costs and benefits for this rule, see the Regulatory Impact Analysis (RIA).

SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE BOILER MACT IN 2014
[Millions of 2008\$]

	3% Discount rate	7% Discount rate
Selected		
Total Monetized Benefits ²	\$22,000 to \$54,000	\$20,000 to \$49,000
Total Social Costs ³	\$1,500	\$1,500
Net Benefits	\$20,500 to \$52,500	\$18,500 to \$47,500
Non-monetized Benefits	112,000 tons of CO, 30,000 tons of HCl, 820 tons of HF, 2,800 pounds of Hg.	
	2,700 tons of other metals, 23 grams of dioxins/furans (TEQ), Health effects from SO ₂ exposure, Ecosystem effects, Visibility impairment.	
Alternative		
Total Monetized Benefits ²	\$18,000 to \$43,000	\$16,000 to \$39,000
Total Social Costs ³	\$1,900	\$1,900
Net Benefits	\$16,100 to \$41,100	\$14,100 to \$37,100
Non-monetized Benefits	112,000 tons of CO, 22,000 tons of HCl, 620 tons of HF, 2,400 pounds of Hg, 2,600 tons of other metals, 23 grams of dioxins/furans (TEQ), Health effects from SO ₂ exposure, Ecosystem effects, Visibility impairment.	

¹ All estimates are for the implementation year (2014), and are rounded to two significant figures. These results include units anticipated to come online and the lowest cost disposal assumption.

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 SO₂, as well as reducing exposure to ozone through reductions of VOCs. It is important to note that the monetized benefits include many but not all health effects associated with PM_{2.5} exposure. Benefits are shown as a range from Pope *et al.* (2002) to Laden *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. These estimates include energy disbenefits valued at \$23 million for the selected option and \$35 million for the alternative option. Ozone benefits are valued at \$3.6 to \$15 million for both options.

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.

III. Summary of This Final Rule

This section summarizes the requirements of this action. Section IV below provides a summary of the significant changes to this final rule following proposal.

A. What is the source category regulated by this final rule?

ICI boilers and process heaters located at major sources of HAP are regulated by

this final rule. Waste heat boilers and boilers and process heaters that combust solid waste, except for specific exceptions to the definition of a solid waste incineration unit outlined in section 129(g)(1), are not subject to this final rule.

B. What is the affected source?

This final rule affects industrial boilers, institutional boilers, commercial

boilers, and process heaters. A process heater is defined as a unit in which the combustion gases do not directly come into contact with process material or gases in the combustion chamber (e.g., indirect fired). A boiler is defined as an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water.

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.

C. What are the pollutants regulated by this final rule?

This final rule regulates HCl (as a surrogate for acid gas HAP), PM (as a surrogate for non-Hg HAP metals), carbon monoxide (CO) (as a surrogate for non-dioxin/furan organic HAP), Hg, and dioxin/furan emissions from boilers and process heaters.

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

You must meet the emission limits presented in Table 1 of this preamble. This final rule includes 15 subcategories. Emission limits are established for new and existing sources for each of the subcategories, which are based on unit design.

Metallic HAP (regulated using PM as a surrogate), HCl, and Hg are “fuel-based pollutants” that are a direct result of contaminants in the fuels that are combusted. For those pollutants, if your new or existing unit combusts at least 10 percent solid fuel on an annual basis, your unit is subject to emission limits that are based on data from all of the solid fuel-fired combustor designs. If your new or existing unit combusts at least 10 percent liquid fuel and less than 10 percent solid fuel and your facility is located in the continental United States, your unit is subject to the liquid fuel

emission limits for the fuel-based pollutants. If your facility is located outside of North America (referred to as a non-continental unit for the remainder of the preamble and in this final rule) and your new or existing unit combusts at least 10 percent liquid fuel and less than 10 percent solid fuel, your unit is subject to the non-continental liquid fuel emission limits for the fuel-based pollutants. Finally, for the fuel-based pollutants, if your unit combusts gaseous fuel that does not qualify as a “Gas 1” fuel, your unit is subject to the Gas 2 emission limits in Table 1 of this preamble. If your unit is a Gas 1 unit (that is, it combusts only natural gas, refinery gas, or equivalent fuel (other gas that qualifies as Gas 1 fuel)), with limited exceptions for gas curtailments and emergencies, your unit is subject to a work practice standard that requires an annual tune-up in lieu of emission limits.

For the combustion-based pollutants, CO (used as a surrogate for non-dioxin organic HAP) and dioxin/furan, your unit is subject to the emission limits for the design-based subcategories shown in Table 1 of this preamble. If your new or existing boiler or process heater burns at least 10 percent biomass on an annual average heat input² basis, the unit is in one of the biomass subcategories. If your new or existing boiler or process heater

burns at least 10 percent coal, on an annual average heat input basis, and less than 10 percent biomass, on an annual average heat input basis, the unit is in one of the coal subcategories. If your facility is located in the continental United States and 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 coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the liquid subcategory. If your non-continental 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 coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the non-continental liquid subcategory. Finally, for the combustion-based pollutants, if your unit combusts gaseous fuel that does not qualify as a “Gas 1” fuel, your unit is subject to the Gas 2 emission limits in Table 1. If your unit combusts only natural gas, refinery gas, or equivalent fuel (other gas that qualifies as Gas 1 fuel), with limited exceptions for gas curtailment and emergencies, your unit is subject to a work practice standard that requires an annual tune-up in lieu of emission limits.

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% oxygen)	Dioxin/furan (TEQ) (ng/dscm)
Existing—Coal Stoker	0.039	0.035	0.0000046	270	0.003
Existing—Coal Fluidized Bed	0.039	0.035	0.0000046	82	0.002
Existing—Pulverized Coal	0.039	0.035	0.0000046	160	0.004
Existing—Biomass Stoker/other	0.039	0.035	0.0000046	490	0.005
Existing—Biomass Fluidized Bed	0.039	0.035	0.0000046	430	0.02
Existing—Biomass Dutch Oven/Suspension Burner	0.039	0.035	0.0000046	470	0.2
Existing—Biomass Fuel Cells	0.039	0.035	0.0000046	690	4
Existing—Biomass Suspension/Grate	0.039	0.035	0.0000046	3,500	0.2
Existing—Liquid	0.0075	0.00033	0.0000035	10	4
Existing—Gas 2 (Other Process Gases)	0.043	0.017	0.000013	9.0	0.08
Existing—non-continental liquid	0.0075	0.00033	0.00000078	160	4
New—Coal Stoker	0.0011	0.0022	0.0000035	6	0.003
New—Coal Fluidized Bed	0.0011	0.0022	0.0000035	18	0.002
New—Pulverized Coal	0.0011	0.0022	0.0000035	12	0.003
New—Biomass Stoker	0.0011	0.0022	0.0000035	160	0.005
New—Biomass Fluidized Bed	0.0011	0.0022	0.0000035	260	0.02
New—Biomass Dutch Oven/Suspension Burner	0.0011	0.0022	0.0000035	470	0.2
New—Biomass Fuel Cells	0.0011	0.0022	0.0000035	470	0.003
New—Biomass Suspension/Grate	0.0011	0.0022	0.0000035	1,500	0.2
New—Liquid	0.0013	0.00033	0.00000021	3	0.002
New—Gas 2 (Other Process Gases)	0.0067	0.0017	0.0000079	3	0.08
New—non-continental liquid	0.0013	0.00033	0.00000078	51	0.002

²Heat 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

from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

The emission limits in Table 1 apply only to new and existing boilers and process heaters that have a designed heat input capacity of 10 million British thermal units per hour (MMBtu/hr) or greater. We also are providing optional output-based standards in this final rule. Pursuant to CAA section 112(h), we are requiring a work practice standard for four particular classes of boilers and process heaters: New and existing units that have a designed heat input capacity of less than 10 MMBtu/hr, 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 for these boilers and process heaters requires the implementation of a tune-up program as described in section III.F of this preamble.

We are also finalizing 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 requirements during periods of startup, shutdown, and malfunction?

Consistent with *Sierra Club v. EPA*, EPA has established standards in this final rule that apply at all times. In establishing the standards in this final rule, EPA has taken into account startup and shutdown periods and, for the reasons explained below, has established different standards for those periods.

EPA has revised this final rule to require sources to meet a work practice standard, which requires following the manufacturer's recommended procedures for minimizing periods of startup and shutdown, for all subcategories of new and existing boilers and process heaters (that would otherwise be subject to numeric emission limits) during periods of startup and shutdown. As discussed in Section V.F of this preamble, we considered whether performance testing, and therefore, enforcement of numeric emission limits, would be practicable during periods of startup and shutdown. EPA determined that it is not technically feasible to complete stack testing—in particular, to repeat the multiple required test runs—during periods of startup and shutdown due to physical limitations and the short duration of startup and shutdown periods. Therefore, we have established

the separate work practice standard for periods of startup and shutdown.

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

Further, it is reasonable to interpret 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 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).

Finally, EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown* (Sept. 20, 1999); *Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions* (Feb. 15, 1983)). EPA is, therefore, adding to this final rule an affirmative defense to civil penalties for exceedances of numerical emission limits that are caused by malfunctions. *See* 40 CFR 63.7575 (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.). We also have added other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 63.7501. (*See* 40 CFR 22.24). The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment,

process equipment, or a process to operate in a normal or usual manner * * *.” The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with section 63.7500(a)(3) and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that “[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *” and that “[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *.” In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with Section 113 of the CAA (see also 40 CFR 22.77).

F. What are the testing and initial compliance requirements?

We are requiring 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 Hg 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 EPA Method 10.

(6) Conduct initial test to determine compliance with the dioxin/furan emission limits using EPA Method 23.

As part of the initial compliance demonstration, we are requiring that you monitor specified operating parameters during the initial performance tests that you would conduct to demonstrate compliance with the PM, Hg, HCl, CO, and dioxin/furan emission limits. You must calculate the average hourly parameter values measured during each test run

over the three run performance test. The lowest or highest hourly average of the three test run 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 requiring to be established for the various types of the following units:

(1) For boilers and process heaters with wet PM scrubbers, you must measure pressure drop and liquid flow rate of the scrubber during the performance test, and calculate the average hourly values during each test run. The lowest hourly average determined during the three test runs establishes your minimum site-specific pressure drop and liquid flow rate operating levels.

(2) If you are complying with an HCl emission limit using a wet acid gas scrubber, you must measure pH and liquid flow rate of the scrubber sorbent during the performance test, and calculate the average hourly values during each test run of the performance test for HCl and determine the lowest hourly average of the pH and liquid flow rate for each test run for the performance test. This establishes your minimum pH and liquid flow rate operating limits.

(3) For boilers and process heaters with sorbent injection, you must measure the sorbent injection rate for each acid gas sorbent used during the performance tests for HCl and for activated carbon for Hg and dioxin/furan and calculate the hourly average for each sorbent injection rate during each test run. The lowest hourly average measured during the performance tests becomes your site-specific minimum sorbent injection rate operating limit. If different acid gas sorbents and/or injection rates are used during the HCl test, the lowest hourly average value for each sorbent becomes your site-specific operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (operating heat input divided by the average heat input during your last compliance test for the appropriate pollutant) to determine the required parameter value.

(4) For boilers and process heaters with fabric filters not subject to PM Continuous Emission Monitoring System (CEMS) or continuous compliance with an opacity limit (*i.e.*, COMS), 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) not subject to PM CEMS or continuous compliance with an opacity limit (*i.e.*, COMS) and you must measure the secondary voltage and secondary current of the ESP collection fields during the Hg and PM performance test. You then calculate the average total secondary electric power value from these parameters for each test run. The lowest average total secondary electric power measured during the three test runs establishes your site-specific minimum operating limit for the ESP.

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

(8) For boilers and process heaters that are subject to a CO emission limit and a dioxin/furan emission limit, you are required to measure the oxygen concentration in the flue gas during the initial CO and dioxin/furan performance test. The lowest hourly average oxygen concentration measured during the most recent performance test is your operating limit, and your unit must operate at or above your operating limit on a 12-hour block average basis.

These operating limits do not apply to owners or operators of boilers or process heaters having a heat input capacity of less than 10 MMBtu/hr or boilers or process heaters of any size which combust natural gas or other clean gas, metal process furnaces, or limited use units, as discussed in section IV.D.3 of this preamble. Instead, owners or operators of such boilers and process heaters shall submit to the delegated authority or EPA, as appropriate, if requested, documentation that a tune-up meeting the requirements of this final rule was conducted. In order to comply with the work practice standard, a tune-up procedure must 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) Optimize total emissions of CO consistent with the manufacturer's specifications,

(5) Measure the concentration in the effluent stream of CO in parts per million by volume dry (ppmvd), before and after the adjustments are made,

(6) Submit to the delegated authority or EPA 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 final rule are required to submit to the delegated authority or EPA, as appropriate, documentation that an energy assessment was performed, by a qualified energy assessor, and the cost-effective energy conservation measures identified.

G. What are the continuous compliance requirements?

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

(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 MMBtu/hr that do not use a wet scrubber, we are requiring 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 MMBtu/hr or greater, we are requiring 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 PM scrubbers, we are requiring 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 to demonstrate continuous compliance with the PM emission limits.

(4) For boilers and process heaters with wet acid gas scrubbers, you must monitor the pH and liquid flow rate of the scrubber and maintain the 12-hour block average at or above the operating limits established during the most recent performance test to demonstrate continuous compliance with the HCl emission limits.

(5) For boilers and process heaters with dry scrubbers, we are requiring that you continuously monitor the sorbent injection rate and maintain it at or above the operating limits, which include an adjustment for load, established during the performance tests. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (operating load divided by the load during your last compliance test for the appropriate pollutant) to determine the required parameter value.

(6) For boilers and process heaters having heat input capacities of less than 250 MMBtu/hr with an ESP, we are requiring that you monitor the voltage and current of the ESP collection plates and maintain the 12-hour block total secondary electric power averages at or above the operating limits established during the Hg or PM performance test.

(7) For units that choose to comply with either the Hg emission limit or the HCl emission limit based on fuel analysis rather than on performance testing, you must maintain monthly fuel records that demonstrate that you burned no new fuels or fuels from a new supplier such that the Hg content or the chlorine content of the inlet fuel was maintained at or below your maximum fuel Hg content operating limit or your chlorine content operating limit set during the performance tests. If you plan to burn a new fuel, a fuel from a new mixture, or a new supplier's fuel that differs from what was burned during the initial performance tests, then you must recalculate the maximum Hg 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 final rule. If the results of recalculating the inputs exceed the average content levels established during the initial test then,

you must conduct a new performance test(s) to demonstrate continuous compliance with the applicable emission limit.

(8) For all boilers and process heaters, except those that are exempt from the incinerator standards under section 129 because they are qualifying facilities burning a homogeneous waste stream, you must maintain records of fuel use that demonstrate that your fuel was not solid waste.

(9) For boilers and process heaters with an oxygen monitor installed for this final rule, you must maintain an oxygen concentration level, on a 12-hour block average basis, no less than lowest hourly average oxygen concentration measured during the most recent performance test.

(10) For boilers and process heaters that demonstrate compliance using a performance test. You must maintain an operating load no greater than 110 percent of the operating load established during the performance test.

If an owner or operator would like to use a control device other than the ones specified in this section to comply with this final 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 are required to comply with certain requirements of the General Provisions (40 CFR part 63, subpart A), which are identified in Table 10 of this final rule. The General Provisions include specific requirements for notifications, recordkeeping, and reporting.

Each owner or operator is required to submit a notification of compliance status report, as required by § 63.9(h) of the General Provisions. This final rule requires 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, are 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 final rule requires 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/hr, units combusting natural gas or other clean gas, metal process furnaces, limited use units, and temporary use units 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 are required.

You are required to keep the following records:

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

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

(3) Each instance in which you did not meet each emission limit and each operating limit (*i.e.*, deviations from this final 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 final rule, for each affected source with an applicable HCl emission limit.

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

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

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

We are also requiring 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, even if you submitted an initial notification for the vacated standards that were promulgated in 2004.

(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

EPA must have performance test data and other compliance 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 ICI boilers located at major source facilities will be required to submit to EPA an electronic copy of reports of certain performance tests required under this final rule. Data will be collected through an electronic emissions test report structure called the Electronic Reporting Tool (ERT) that will be used by the 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) is scheduled to 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 below 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 collecting 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 final 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 likely 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 because 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 database accessible through EPA's TTN. The WebFIRE database was constructed to store emissions test and other 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>.

Source owners and operators will be able to transmit data collected via the ERT 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.

Source owners and operators must register with the CDX system to obtain a user name and password before being able to submit data to the CDX. The CDX registration page can be found at: <https://cdx.epa.gov/SSL/CDX/regwarning.asp?Referer=registration>. If they have a current CDX account (e.g., they submit reports for EPA's Toxic Release Inventory Program to the CDX), then the existing user name and password can be used to log in to the CDX.

IV. Summary of Significant Changes Since Proposal

A. Applicability

Since proposal, several changes to the applicability of this final rule have been made. First, at proposal, we excluded all units that combust solid waste from the standards, but we have extended the coverage of this final rule to boilers and process heaters that combust solid waste but are exempt, by statute, from section 129 incinerator rules because they are qualifying small power producers or cogeneration units that combust a homogeneous waste stream. This final rule continues to exclude other waste burning units. This is a clarifying change that is consistent with the intent of the proposed rule to establish

emissions standards for all boilers and process heaters that are not solid waste incineration units subject to regulation under section 129.

The proposed rule definition of coal was revised to include all types of fossil-based fuels in the coal definition. The final coal definition is: "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, "Standard Specification for Classification of Coals by Rank" (incorporated by reference, see § 63.14(b)), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes 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. Coal derived gases are excluded from this definition." Similarly, for biomass, the definition of biomass fuel was revised to include any potential biomass-based fuels. This is also a clarifying change consistent with the intent of the proposed rule as described above. The final definition is: "Biomass or bio-based solid fuel means any solid biomass-based fuel that is not a solid waste. This may include, but is not limited to, the following materials: Wood residue; 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 not solid waste."

The proposed rule included a definition of waste heat boiler that excluded from the definition units with supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity. The final definition was revised to include all waste heat boilers. The final definition is: "Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators." Similarly, the waste heat process heater definition was revised to read as follows: "Waste heat process heater means an enclosed device that recovers normally unused energy and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process

heaters." These changes were made in order to exempt the types of units intended at proposal.

The proposed rule exempted blast furnace gas fuel-fired boiler or process heaters, and defined these units as units combusting 90 percent or more of its total heat input from blast furnace gas. We have changed the requirement to 90 percent or more of its total volume of gas in this final rule. This change was made so that the units that were intended to be exempted from this final rule would be exempted. The wording of the proposed exemption did not exempt units that were intended to be exempted because the heating value of blast furnace gas is not as high as that of natural gas.

The proposed rule exempted units that are an affected source in another MACT standard. We amended this language to include any unit that is part of the affected source subject to another MACT standard. We also exempted any unit that is used as a control device to comply with another MACT standard, provided that at least 50 percent of the heat input is provided by the gas stream that is regulated under another MACT standard. This change was made in order to encourage the recovery of energy from high heating value gases that would otherwise be flared.

B. Subcategories

In the proposed rule, for the fuel-dependent HAP (metals, Hg, acid gases), we identified the following five basic unit types as subcategories: (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. In this final rule, for fuel-dependent HAP, we combined the subcategories for units designed to combust coal and biomass into a subcategory for units designed to burn solid fuels. We changed the subcategory for units designed to burn natural gas/refinery gas to a subcategory for units that burn natural gas, refinery gas, and other clean gas. We also added subcategories for non-continental liquid units and limited-use units.

As described in the preamble to the proposed rule, within the basic unit types there are different designs and combustion systems that, while having a minor effect on fuel-dependent HAP emissions, have a much larger effect on pollutants whose emissions depend on the combustion conditions in a boiler or process heater. In the case of boilers and process heaters, the combustion-related pollutants are the organic HAP. In the proposed rule, we identified the

following 11 subcategories for organic HAP: (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. In this final rule, we added subcategories for biomass suspension/grate units, non-continental liquid units, and limited-use units.

C. Emission Limits

The proposed rule included numerical emission limits for PM, Hg, HCl, CO, and dioxin/furan, and limits for those same pollutants are included in this final rule. Unlike the proposed rule, we included a compliance alternative in the final rule to allow owners and operators of existing affected sources to demonstrate compliance on an output-basis instead of on a heat input basis. Compliance with the alternate output-based emission limits would require measurement of boiler operating parameters associated with the mass rate of emissions and energy outputs. If you elect to comply with the alternate output-based emission limits, you must use equations provided in the final rule to demonstrate that emissions from the applicable units do not exceed the output-based emission limits specified in the final rule. If you use this compliance alternative using the emission credit approach, you must also establish a benchmark, calculate and document the emission credits generated from energy conservation measures implemented, and develop and submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance.

D. Work Practices

This final rule includes work practice standards for most of the same units for which we proposed work practice standards, including new and existing units in the Gas 1 subcategory, existing units with heat input capacity less than 10 MMBtu/hr, and new and existing metal process furnaces. In addition to those subcategories for which we proposed work practices, this final rule includes work practices for all units during periods of startup and shutdown, new units with heat input capacity less than 10 MMBtu/hr, limited use units,

and units combusting other clean gases. Other clean gases are gases, other than natural gas and refinery gas (as defined in this final rule), that meet contaminant level specifications that are provided in the final rule.

E. Energy Assessment Requirements

In this final rule, we have expanded the definition of energy assessment with respect to the requirements of Table 3 of this final rule, by providing a duration for performing the energy assessment and defining the evaluation requirements for each boiler system and energy use system. These requirements are based on the total annual heat input to the affected boilers and process heaters.

This final rule requires an energy assessment for facilities with affected boilers and process heaters using less than 0.3 trillion Btu per year (TBtu/y) heat input to be one day in length maximum. The boiler system and energy use system accounting for at least 50 percent of the energy output from these units must be evaluated to identify energy savings opportunities within the limit of performing a one day energy assessment. An energy assessment for a facility with affected boilers and process heaters using 0.3 to 1 TBtu/year must be three days in length maximum. From these boilers, the boiler system and any energy use system accounting for at least 33 percent of the energy output will be evaluated, within the limit of performing a three day energy assessment. For facilities with affected boilers and process heaters using greater than 1 TBtu/year heat input, the energy assessment must address the boiler system and any energy use system accounting for at least 20 percent of the energy output to identify energy savings opportunities.

The expanded definition for energy assessment clarifies the duration and requirements for each energy assessment for various units based on energy use. We have also added a definition for steam and process heating systems to clarify the components for each boiler system which must be considered during the energy assessment, including elements such as combustion management, thermal energy recovery, energy resource selection, and the steam end-use management of each affected boiler.

Lastly, we have clarified the requirement in Table 3 to evaluate facility energy management practices as part of the energy assessment and a definition of an energy management program was added. The use of the ENERGY STAR Facility Energy Assessment Matrix as part of this review

is recommended, but it was removed as a requirement in Table 3. The definition of an energy management program added to the rule is consistent with the ENERGY STAR Guidelines for Energy Management that can be referenced for further guidance. ENERGY STAR provides a variety of tools and resources that support energy management programs. For more information, visit <http://www.energystar.gov>.

F. Requirements During Startup, Shutdown, and Malfunction

For startup, shutdown, and malfunction (SSM), the requirements have changed since proposal. For periods of startup and shutdown, EPA is finalizing work practice standards, which require following manufacturers specifications for minimizing periods of startup and shutdown, in lieu of numeric emission limits. For malfunctions, EPA added affirmative defense language to this final rule for exceedances of the numerical emission limits that are caused by malfunctions.

G. Testing and Initial Compliance

The first significant change to the testing and initial compliance requirements is that units greater than 100 MMBtu/hr must comply with the CO limits using a stack test rather than CO CEMS. EPA also added optional output-based limits that promote energy efficient boiler operation. Another significant change is that for units combusting gaseous fuels other than natural gas or refinery gas, in order to qualify for the Gas 1 subcategory work practice standard, the gases that will be combusted must be certified to meet the contaminant levels specified for Hg and hydrogen sulfide (H₂S) in this final rule. Finally, EPA has changed the dioxin/furan testing requirement to a one-time compliance demonstration due to the low dioxin/furan emissions demonstrated by the vast majority of sources that have tested for dioxin/furan.

H. Continuous Compliance

The only significant change to the continuous compliance requirements is for monitoring of CO. Rather than using CO CEMS, as proposed, units will be required to continuously monitor and record the oxygen level in their flue gas during the initial compliance test and establish an operating limit that requires that the unit operate at an oxygen percentage of at least 90 percent of the operating limit on a 12-hour block average basis. Units will be required to continuously monitor oxygen to ensure continuous compliance.

I. Notification, Recordkeeping, and Reporting

In this final action, we are requiring that owners or operators of boilers that choose to commence or recommence combustion of solid waste must provide 30 days notice of the date upon which the source will commence or recommence combustion of solid waste. The notification must identify the name of the owner or operator of the affected source, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice; the currently applicable subcategory under this subpart; the date on which the unit became subject to the currently applicable emission limits; and the date upon which the unit will commence or recommence combusting solid waste.

For each limited-use unit, owners or operators must monitor and record the operating hours on a monthly basis for the unit. This will ensure that units qualify for the limited-use subcategory.

We also added a requirement that sources keep records of operating load in order to demonstrate continuous compliance with the operating load operating limit.

When malfunctions occur, owners or operators must keep records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment, as well as records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

Finally, for facilities that elect to use emission credits from energy conservation measures to demonstrate compliance, owners or operators must keep a copy of the Implementation Plan required in this rule and copies of all data and calculations used to establish credits.

J. Technical/Editorial Corrections

In this final action, we are making a number of technical corrections and clarifications to subpart DDDDD. These changes improve the clarity and procedures for implementing the emission limitations to affected sources. We are also clarifying several definitions to help affected sources determine their applicability. We have modified some of the regulatory language that we proposed based on public comments.

In several places throughout the subpart, including the associated tables,

we have corrected the cross-references to other sections and paragraphs of the subpart.

We revised 40 CFR 63.7485 to clarify that for the purposes of subpart DDDDD, a major source of HAP is as defined in 40 CFR 63.2, except that for oil and gas facilities a major source of HAP is as defined in 40 CFR 63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities). This change was made because facilities subject to subpart HH contain units that will be subject to subject DDDDD.

The word “specifically” was removed from § 63.7491(i) in order to clarify the exclusion for boilers and process heaters regulated by other HAP regulations.

We revised 40 CFR 63.7505(c) to clarify that performance testing is needed only if a boiler or process heater is subject to an applicable emission limit listed in Table 2.

We made several changes to the initial compliance demonstration requirements. We revised 40 CFR 63.7510(a) to clarify that sources using a second fuel only for start up, shut down, and/or transient flame stability are still considered to be sources using a single fuel. We revised 40 CFR 63.7510(c) to clarify that boilers and process heaters with a heat input capacity below 10 MMBtu per hour are not required to conduct a performance test for CO because they are not subject to a numerical emission limit for CO. In 40 CFR 63.7510(d), we clarified that boilers and process heaters that use a CEMS for PM are exempt from the performance testing and operating limit requirements specified in 40 CFR 63.7510(a) because the CEMS demonstrates continuous compliance. We revised 40 CFR 63.7510(c) and (d) to clarify that compliance for those provisions does not apply to units burning natural gas or refinery gas.

We changed the performance testing requirements in 40 CFR 63.7515(b), (c), and (d) to state that performance testing for a given pollutant may be performed every 3 years, instead of annually, if measured emissions during 2 consecutive annual performance tests are less than 75 percent of the applicable emission limit.

In 40 CFR 63.7515(e), we clarified that boilers and process heaters with a heat input capacity below 10 MMBtu per hour are required to conduct tune-ups biennially, while larger natural gas and other Gas 1 units are required to conduct annual tune-ups.

We revised 40 CFR 63.7515(f) to clarify that monthly fuel analyses are

required only for fuel types for which emission limits apply.

We made several changes to 40 CFR 63.7520 to clarify the performance testing requirements. We revised paragraph (c) to clarify that performance tests must be conducted at representative operating load conditions, instead of at the maximum normal operating load. Language was also added to this section and to Table 4 to subpart DDDDD to establish an operating limit for the boiler or process heater and clarified that the operating load must not exceed 110 percent of the load used during the performance test. We revised paragraph (d) to clarify that compliance with operating limits using a continuous parameter monitoring systems are based on the 4-hour block averages of the data collected by the continuous parameter monitoring systems.

In 40 CFR 63.7522, we made several changes to the provisions for using emissions averaging. In paragraph (a), we clarified that average emissions must be “* * * not more than 90 percent of the applicable emission limit.” We also added a sentence to clarify that new boilers and process heaters may not be included in an emissions average used to demonstrate compliance according to that section. Equations 2 and 3 were revised to correct the discount factor from 0.9 to 1.1 because the actual emissions are multiplied by the discount factor. We also revised paragraph (c) to clarify that the deadline to establish emission caps to demonstrate compliance with the emission averaging option is 60 days after the publication of the final rule as referenced in paragraph (g)(2)(i), and revised paragraph (g) to clarify that facilities are required to submit an implementation plan as referenced in § 63.7522(g)(1).

We made several clarifying changes to the monitoring requirements in 40 CFR 63.7525. We revised paragraph (a) to clarify that only boilers or process heaters subject to a CO limit are required to install a continuous oxygen monitoring system. We adopted language from § 63.7525(d)(2) to § 63.7525(a)(6) to clarify what constitutes a deviation. In 40 CFR 63.7525(c)(7), we clarified that owners/operators are required to determine 6-minute and daily block averages excluding data from periods in which the continuous opacity monitoring system is out of control.

The initial compliance provisions in 40 CFR 63.7530(b) were revised to clarify that facilities are exempted from the initial compliance requirements of conducting a fuel analysis if only one

fuel type is used. We revised 40 CFR 63.7530(d) to clarify that units less than 10 MMBtu per hour are required to submit a signed statement with the Notification of Compliance Status report that indicates a tune-up has been conducted.

We revised 40 CFR 63.7540(a)(9)(i) to remove the reference to Procedure 2 in Appendix F to 40 CFR part 60; Procedure 2 specifies the ongoing QA/QC requirements for PM CEMS after certification and is correctly referenced in paragraph (a)(9)(iii) of that section.

We revised the notification requirements in 40 CFR 63.7545 to clarify that notifications should be submitted to the delegated authority, and to clarify that the Notification of Intent to conduct a performance test must be submitted 60 days before the test is scheduled to begin.

The reporting requirements originally in 40 CFR 63.7550(g) and (g)(1) through (g)(3) are more correctly considered notification requirements, so they were moved to § 63.7545(e)(8).

In response to comments asking for clarification, we have added definitions to 40 CFR 63.7575 for “Calendar year,” “Operating day,” “Refinery gas,” and “Valid hourly average.” We have also revised several definitions in that section based on public comments. For example, we revised the definition of “boiler” to describe what is meant by the term “controlled flame combustion” as used in that definition; revised “metal processing furnace” to include homogenizing furnaces; revised the definitions of “dry scrubber,” “electrostatic precipitator,” and “fabric filter,” to indicate that these are all considered dry control systems. The definition of “wet scrubber” was revised to clarify that, “A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.”

The definition of “Tune-up” was removed from 40 CFR 63.7575 because all of the requirements for a tune-up are provided in the rule language at 40 CFR 63.7540(a)(10), making the definition unnecessary.

Several of the definitions in 40 CFR 64.7575 were revised to clarify the types of equipment to which different standards apply. For example, the definition of “Temporary boiler” was revised to include additional criteria that could be used to identify temporary boilers from permanently installed units. The definition of “Unit designed to burn oil subcategory” was revised to exclude periods of gas curtailment and gas supply emergency from the 48-hour limit on liquid fuel combustion. Likewise, the definition of “Period of

natural gas curtailment” was revised to clarify that contractual agreements for curtailed gas usage or fluctuations in price do not constitute periods of gas curtailment under the scope of this regulation. The definition of “Waste heat boiler” was revised to remove the criteria that 50 percent of total rated heat input capacity had to be from waste gases. We also revised the definition of “Natural gas” to include gas derived from naturally occurring mixtures found in geological formations as long as the principal constituent is methane, consistent with the definition provided in 40 CFR part 60 subpart Db. A definition of propane, was also incorporated into the definition of natural gas.

Several changes were made to the tables to subpart DDDDD as a result of the public comments on the proposed rule.

In Tables 1 and 2, the references to “Other gases” were revised to “Gas 2” to clarify that units burning natural gas, refinery gas, or other clean gases are not subject to emission limitations. The emission limits in these two tables were also revised to include averaging times for those pollutants for which measurements are taken with a continuous emission monitor.

In Table 3, the references to “§ 63.11202 and § 63.11203” in the table heading were revised to correctly reference 40 CFR 63.7540. The text in the first and second column of Table 3 was revised to clarify that the requirements apply to both boilers and process heaters. A new row was added to clarify that work practice standards apply to new boilers or process heaters with a rated heat input capacity less than 10 MMBtu per hour. Language was also added to clarify that the energy assessment is a one-time requirement for existing boilers and process heaters. Additionally, new language was added clarifying the evaluation of the facility’s energy management program as part of the energy assessment.

In Table 4, operating limits for pH added to Item 1 for wet scrubbers, as specified in 40 CFR 63.7530(b)(3)(i). Item 5 revised to clarify that “Any other control type” only means add-on air-pollution control devices. The operating limits were also revised to clarify which units and control combinations were required to install and operate a bag leak detection system, to install and operate a continuous opacity monitor, or to monitor voltage and amperage of an ESP. These changes removed the appearance that some units would need to do more than one type of monitoring for control of PM. This table was also revised to include a row for an operating

limit for unit operating load for those units that demonstrate compliance using a performance test.

Table 5 was revised to include EPA Method 23 as the accepted method for measuring dioxin/furan. A new Table 11 was also added to document the toxic equivalency factors that should be used to demonstrate compliance with the toxic equivalents (TEQ) emission limits.

Table 7 was revised to include dry scrubbers and activated carbon injection used to comply with Hg or dioxin/furan emission limitations, and to include procedures for determining the corresponding operating limit requirements. Procedures were also added for determining the operating limit for unit operating load for units that demonstrate compliance through performance testing. Finally, this table was revised to clarify how the operating limits should be determined for wet scrubbers and for ESPs operated with wet scrubbers.

Table 8 was revised to correct certain cross-references to 40 CFR 63.7530, and to include procedures for demonstrating continuous compliance with the operating limit for unit operating load.

Table 9 was revised to correct cross-references to 40 CFR 63.7550(c) and Table 3 for work practice standards. Language in Item 1.c. revised to more clearly match the language in 40 CFR 63.7530(d) and (e), and Item 1.c. was split into Items 1.c. and 1.d.

K. Other

The definition of a boiler and the definition of a process heater have been revised to include units that combust solid waste but are exempt, by statute, from section 129. This change was necessary in order to provide coverage of units that would otherwise be exempt from any requirements. The revised definitions read as follows:

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. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in 40 CFR 241.3, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in CAA section 129(g)(1). Waste heat boilers are excluded from this definition.

Process heater means an enclosed device using controlled flame, 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. For purposes of this subpart, a device combusting solid waste, as defined in 40 CFR 241.3, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in CAA section 129(g)(1). Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.

As a result of new data received for the floor calculations, revised treatment of low reported CO data to consider measurement error, and a new subcategorization scheme, some of the final CO limits for new sources in Table 1 of this final rule are more stringent than proposed, as are some of the other limits for certain subcategories (e.g., PM and Hg for liquid fuel units, and PM and HCl for solid fuel units when compared to the proposed new source limits for the proposed biomass/bio-based fuel subcategory). Where a final limit is more stringent than proposed, 40 CFR 63.6 of subpart A (General Provisions), requires that new sources that commenced construction between proposal and promulgation be allowed to comply with the proposed limits for 3 years (i.e., up to the existing source compliance date) and then comply with the final limits for new sources listed in Table 1 of this final rule. In this final rule we have added a new Table 12 to outline the emission limits applicable to sources that commenced construction between proposal and promulgation and updated the rule language to provide instructions on which limits apply to them for the 3 year period after this final rule is published. These sources have the option to comply with Table 1 (final) limits from the start, if they choose.

V. Major Source Public Comments and Responses

A. MACT Floor Analysis

1. Pollutant-by-Pollutant Approach

Comment: Many commenters raised concerns about the way EPA determined the MACT floors using a pollutant-by-pollutant approach. Commenters contended that such a methodology produced limits that are not achievable in combination, and as such, the limits do not comport with the intent of the statute or the recent court decision (*NRDC v. EPA*, 2007). Commenters argue that while the Court's 2007 decision in *NRDC v. EPA* vacating the first ICI boiler and process heater MACT standard directed EPA to consider

individual HAPs, it did not direct EPA to establish a separate floor for each HAP. Commenters further added that the Clean Air Act (CAA) directs EPA to set standards based on the overall performance of "sources" and sections 112(d)(1), (2), and (3) specify that emissions standards be established on the "in practice" performance of a "source" in the category or subcategory. If Congress had intended for EPA to establish MACT floor levels considering the achievable emission limits of individual HAPs, it could have worded 112(d)(3) to refer to the best-performing sources "for each pollutant." Many commenters added that EPA's discretion in setting standards is limited to distinguishing among classes, types, and sizes of sources. However, Congress limited EPA's authority to parse units and sources with similar design and types but it does not allow EPA to "distinguish" units and sources by individual pollutant as proposed in this rule [*Sierra Club v. EPA*, 551 F.3d 1019, 1028 (D.C. Cir. 2008)]. By calculating each MACT floor independently of the other pollutants, the combination of HAP limits results in a set of standards that only a hypothetical "best performing" unit could achieve.

Many commenters who criticized the pollutant-by-pollutant approach also filed comments on other rules such as the recent Portland Cement NESHAP and the NSPS and Emission Guidelines for Hospital/Medical Infectious Waste Incinerators (HMIWI). Some commenters expressed concern that EPA used a similar pollutant-by-pollutant approach in the HMIWI rulemaking and that rulemaking is being challenged before the D.C. Circuit. Commenters also submitted a variety of suggestions on calculating a multi-pollutant approach. Some commenters suggested that human health be considered by weighting pollutants according to relative-toxicity and then ranking the units in each subcategory according to their weighted emission totals in order to identify the best performing 12 percent of sources for all pollutants.

Response: We disagree with the commenters who believe MACT floors cannot be set on a pollutant-by-pollutant basis. Contrary to the commenters' suggestion, section 112(d)(3) does not mandate a total facility approach. A reasonable interpretation of section 112(d)(3) is that MACT floors may be established on a HAP-by-HAP basis, so that there can be different pools of best performers for each HAP. Indeed, as illustrated below, the total facility approach not only is not compelled by the statutory language

but can lead to results so arbitrary that the approach may simply not be legally permissible.

Section 112(d)(3) is ambiguous as to whether the MACT floor is to be based on the performance of an entire source or on the performance achieved in controlling particular HAP. Congress specified in section 112(d)(3) the minimum level of emission reduction that could satisfy the requirement to adopt MACT. For new sources, this floor level is to be "the emission control that is achieved in practice by the best controlled similar source." For existing sources, the floor level is to be "the average emission limitation achieved by the best performing 12 percent of the existing sources" for categories and subcategories with 30 or more sources, or "the average emission limitation achieved by the best performing 5 sources" for categories and subcategories with fewer than 30 sources. Commenters point to the statute's reference to the best performing "sources," and claim that Congress would have specifically referred to the best performing sources "for each pollutant" if it intended for EPA to establish MACT floors separately for each HAP. EPA disagrees. The language of the Act does not address whether floor levels can be established HAP-by-HAP or by any other means. The reference to "sources" does not lead to the assumption the commenters make that the best performing sources can only be the best-performing sources for the entire suite of regulated HAP. Instead, the language can be reasonably interpreted as referring to the source as a whole or to performance as to a particular HAP. Similarly, the reference in the new source MACT floor provision to "emission control achieved by the best controlled similar source" can mean emission control as to a particular HAP or emission control achieved by a source as a whole.

Industry commenters also stressed that section 112(d) requires that floors be based on actual performance from real facilities, pointing to such language as "existing source", "best performing", and "achieved in practice". EPA agrees that this language refers to sources' actual operation, but again the language says nothing about whether it is referring to performance as to individual HAP or to single facility's performance for all HAP. Industry commenters also said that Congress could have mandated a HAP-by-HAP result by using the phrase "for each HAP" at appropriate points in section 112(d). The fact that Congress did not do so does not compel any inference that Congress was *sub-silentio* mandating a different result

when it left the provision ambiguous on this issue. The argument that MACT floors set HAP-by-HAP are based on the performance of a hypothetical facility, so that the limitations are not based on those achieved in practice, just re-begs the question of whether section 112(d)(3) refers to whole facilities or individual HAP. All of the limitations in the floors in this rule of course reflect sources' actual performance and were achieved in practice. Finally, there are a number of existing units that *meet all* of the final existing source emission limits.

Commenters also point to EPA's subcategorization authority, and claim that because Congress authorized EPA to distinguish among classes, types, and sizes of units, EPA cannot distinguish units by individual pollutant, as they allege EPA did in the proposed rule. However, that statutory language addresses EPA's authority to subcategorize sources within a source category prior to setting standards, which EPA has done for boilers and process heaters. EPA is not distinguishing within each subcategory based on HAP emitted. Rather, it is establishing emissions standards based on the emissions limits achieved by units in each subcategory. Therefore, EPA's subcategorization authority is irrelevant to the question of how EPA establishes MACT floor standards once it has made the decision to distinguish among sources and create subcategories.

EPA's long-standing interpretation of the Act is that the existing and new source MACT floors are to be established on a HAP-by-HAP basis. One reason for this interpretation is that a whole plant approach could yield least common denominator floors—that is floors reflecting mediocre or no control, rather than performance which is the average of what best performers have achieved. *See* 61 FR at 173687 (April 19, 1996); 62 FR at 48363–64 (September 15, 1997) (same approach adopted under the very similar language of section 129(a)(2)). Such an approach would allow the performance of sources that are outside of the best-performing 12 percent for certain pollutants to be included in the floor calculations for those same pollutants, and it is even conceivable that the worst performing source for a pollutant could be considered a best performer overall, a result Congress could not have intended. Inclusion of units that are outside of the best performing 12 percent for particular pollutants would lead to emission limits that do not meet the requirements of the statute.

For example, if the best performing 12 percent of facilities for HAP metals were

also the worst performing units for organics, the floor for organics or metals would end up not reflecting best performance. In such a situation, EPA would have to make some type of value judgment as to which pollutant reductions are most critical to decide which sources are best controlled.³ Such value judgments are antithetical to the direction of the statute at the MACT floor-setting stage. Commenters suggested that a multi-pollutant approach could be implemented by weighting pollutants according to relative toxicity and calculating weighted emissions totals to use as a basis for identifying and ranking best performers. This suggested approach would require EPA to essentially prioritize the regulated HAP based on relative risk to human health of each pollutant, where risk is a criterion that has no place in the establishment of MACT floors, which are required by statute to be based on technology.

The central purpose of the amended air toxic provisions was to apply strict technology-based emission controls on HAPs. *See, e.g.,* H. Rep. No. 952, 101st Cong. 2d sess. 338. The floor's specific purpose was to assure that consideration of economic and other impacts not be used to “gut the standards. While costs are by no means irrelevant, they should by no means be the determining factors. There needs to be a minimum degree of control in relation to the control technologies that have already been attained by the best existing sources.” A Legislative History of the Clean Air Act *Vol. II* at 2897 (statement of Rep. Collins). An interpretation that the floor level of control must be limited by the performance of devices that only control some of these pollutants effectively “guts the standards” by including worse performers in the averaging process, whereas EPA's interpretation promotes the evident Congressional objective of having the floor reflect the average performance of best performing sources. Since Congress has not spoken to the precise question at issue, and the Agency's interpretation effectuates statutory goals and policies in a reasonable manner, its interpretation must be upheld. *See Chevron v. NRDC*, 467 U.S. 837 (1984).⁴

³ *See* Petitioners Brief in *Medical Waste Institute et al. v. EPA*, No. 09–1297 (D.C. Cir.) pointing out, in this context, that “the best performers for some pollutants are the worst performers for others” (p. 34) and “[s]ome of the best performer for certain pollutants are among the worst performers for others.”

⁴ Since industry commenters argued that the statute can only be read to allow floors to be determined on a single source basis, commenters

It is true that legislative history can sometimes be so clear as to give clear meaning to what is otherwise ambiguous statutory text. As just explained, EPA's HAP-by-HAP approach fulfills the evident statutory purpose and is supported by the most pertinent legislative history. A few industry commenters nonetheless indicated that a HAP-by-HAP approach is inconsistent with legislative history to section 112(d), citing to page 169 of the Senate Report. Since this Report was to a version of the bill which did not include a floor provision at all (much less the language at issue here), it is of no relevance. *National Lime II*, 233 F. 3d at 638.

Industry commenters also noted that EPA retains the duty to investigate and, if justifiable, to adopt beyond the floor standards, so that potential least common denominator floors resulting from the whole facility approach would not have to “gut the standards.” That EPA may adopt more stringent standards based on what is “achievable” after considering costs and other factors is irrelevant to how EPA is required to set MACT floors. MACT floors must be based on the emission limitation achieved by the best performing 12 percent of existing sources, and, for new sources, on the level achieved by the best controlled similar source, and EPA must make this determination without consideration of cost. At best, standards reflecting a beyond-the-floor level of performance will have to be cost-justified; at worst, standards will remain at levels reflecting mediocre performance. Under either scenario, Congress' purpose in requiring floors is compromised.

EPA notes, however, that if optimized performance for different HAPs is not technologically possible due to mutually inconsistent control technologies (for example, metals performance decreases if organics reduction is optimized), then this would have to be taken into account by EPA in establishing a floor (or floors). The Senate Report indicates that if certain types of otherwise needed controls are mutually exclusive, EPA is to optimize the part of the standard providing the most environmental protection. S. Rep. No. 228, 101st Cong. 1st sess. 168 (although, as noted, the bill accompanying this Report contained no floor provisions). It should be

offered no view of why their reading could be viewed as reasonable in light of the statute's goals and objectives. It is not evident how any statutory goal is promoted by an interpretation that allows floors to be determined in a manner likely to result in floors reflecting emissions from worst or mediocre performers.

emphasized, however, that “the fact that no plant has been shown to be able to meet all of the limitations does not demonstrate that all the limitations are not achievable.” *Chemical Manufacturers Association v. EPA*, 885 F. 2d at 264 (upholding technology-based standards based on best performance for each pollutant by different plants, where at least one plant met each of the limitations but no single plant met all of them).

All available data for boilers and process heaters indicate that there is no technical problem achieving the floor levels contained in this final rule for each HAP simultaneously, using the MACT floor technology. Data demonstrating a technical conflict in meeting all of the limits have not been provided, and, in addition, there are a number of units that meet all of the final existing source emission limits.

2. Minimum Number of Units To Set New Source Floors

Comment: Many commenters indicated that section 112 requires that data from a minimum of 5 units is required to set MACT floors for existing sources. Commenters noted that EPA’s use of less than 5 units for subcategories with greater than 30 units is a legalistic reading of section 112 that could result in such absurd results as using 5 units to set MACT floors for a subcategory with 29 units and data for only 10 units, but using a single unit to set MACT floors for a subcategory with 31 units and data for only 10 units.

Response: EPA does not agree that section 112(d)(3) mandates a minimum of 5 sources in all instances, notwithstanding the incongruity of having less data to establish floors for larger source categories than is mandated for smaller ones. The literal language of the provision appears to compel this result. Section 112(d)(3) states that for categories and subcategories with at least 30 sources, the MACT floor for existing sources shall be no less stringent than the average emission limitation achieved by the best-performing twelve percent of the sources for which the Administrator has emissions information. The plain language of this provision requires that, for subcategories with at least 30 sources but where the Administrator only has emissions information on a small number of units, the floor can be no less stringent than the average emission limitation achieved by the best-performing twelve percent of those sources.

3. Treatment of Detection Levels

Comment: When setting the MACT floors, non-detect values are present in many of the datasets from best performing units. Commenters provided input on how these non-detect values should be treated in the MACT floor analysis. Some commenters agreed that it is appropriate to keep the detection levels as reported; while certain commenters suggested that the detection levels should be replaced using a value of half the method detection limit (MDL). Many other commenters stated that data that are below the detection limit should not be used in setting the floors, and these data should be replaced with a higher value including either the MDL, limit of quantitation (LOQ), practical quantitation limit (PQL), or reporting limit (RL) for the purposes of the MACT floor calculations. Other commenters stated all non-detect values should be excluded from the floor analysis, or all values should be treated as 0. Some commenters stated it is necessary to keep the data as reported because changing values would lead to an upward bias. Additional commenters agreed with this basic premise, but suggested that replacing non-detect data with a value of half the MDL is appropriate while still minimizing the bias. They noted that treating measurements below the MDL as occurring at the MDL is statistically incorrect and violates the statute’s “shall not be less stringent than” requirement for MACT floors. One commenter also provided a reference for a statistical method based on a log-normal distribution of the data which estimated the “maximum likelihood” of data values; this result is slightly higher than half the MDL. Some commenters stated that it is necessary to substitute the MDL value when performing the MACT floor calculations. With MDL defined as the lowest concentration that can be distinguished from the blank at a defined level of statistical significance, this is an appropriate value. If MDL values are not reported, one commenter suggested an approach for estimating an MDL equivalent value, but recognized that the background laboratory and test report files may not be available to EPA in order to derive these estimates. Most commenters representing industry and industry trade groups argued that either LOQ or PQL values should replace non-detects. The LOQ is defined as the smallest concentration of the analyte which can be measured. These commenters contended that the LOQ leads to a quantifiable amount of the substance with an acceptable level of

uncertainty. A few commenters provided calculations showing some of the proposed MACT floors were below the LOQ. Additionally, some of these commenters stated that using LOQ or PQL values also incorporates additional sources of random and inherent sampling error throughout the testing process, which is necessary. These errors occur during sample collection, sample recovery, and sample analysis; MDL values only account for method specific (e.g., instrument) errors. These commenters contended that the three times the MDL approach discussed in the proposal accounts for some measurement errors but does not account for these unavoidable sampling errors. The commenters also noted that an LOQ is calculated as 3.18 times the MDL, and PQL is calculated as 5–10 times the MDL. Many of the commenters in support of using either an LOQ or PQL value ultimately believed a work practice is more appropriate where a MACT floor limit is below either of these two values. They cited 112(h)(1) which allows work practices under 112(h)(2) if “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations”. These commenters stated that the inability of sources to accurately measure a pollutant at the level of the MACT floor qualifies as such a technological limitation that warrants a work practice standard.

Where the proposed MACT floor is below the LOQ or PQL then that source category has a technological measurement limitation. A few commenters suggested RL values should be used when developing the floor limits. They stated that the RL is the lowest level at which the entire analytical system gives reliable signals and includes an acceptable calibration point. They added that use of an acceptable calibration point is critical in showing that numbers are real versus multiplying the MDL by various factors.

Several commenters stated that all non-detect values should be excluded from MACT floor calculations. They believed that excluding all non-detect values would eliminate any potential errors or accuracy issues related to testing for compliance. Due to inconsistencies of the MDL value reported for non-detect data, one commenter suggested treating all such values as zero. This would provide a consistent approach for setting the floor as well as determining compliance. Issues discussed by a multitude of commenters were that a wide range of detection limit values were reported and

that data from Phase I and Phase II information collection requests (ICR) are inconsistent. For all non-detect data, facilities participating in the Phase II ICR were instructed to report a detection limit, but this resulted in a variety of interpretations by the laboratories who reported data. As such, commenters provided examples where detected values were lower than non-detect values, and in some cases measured values were reported lower than typical method detection limits. Many of the commenters stated it is critical that EPA conduct a thorough quality review of the data to determine if non-detect values have been appropriately flagged and to normalize the data on a consistent basis. One commenter presented an example dataset and the potential implications of the treatment of non-detect data for Hg emissions in the biomass subcategory. This commenter noted that a number of the units with Phase I tests would no longer be considered top performers if their data were made consistent with the Phase II criteria. Several commenters provided remarks for EPA's proposed method of three times the MDL as an option for setting limits. A few commenters in support noted that this approach provided a reasonable method to account for data variability as it took into account more than just analytical instrument precision. Many other commenters argued that this method results in limits which are too low, namely that it is still lower than the LOQ value which they are in favor of as a substitute for any reported non-detect data. On the contrary, some other commenters disagreed with this method and claimed that it would lead to results which introduce a high bias in the floor setting process. A few contended that multiplying by 3 would introduce a 300 percent error into the floor, resulting in a floor that is less stringent than required by the Act. Others suggested that the MDL values are antiquated and already too high and thus it is not appropriate to multiply them by three. Also, a few commenters suggested multiplying the MDL by three would not reflect the actual lower emissions achieved by any source and as such is unlawful under section 112(d).

Response: After consideration of the various comments related to treatment of detection limits in the development of MACT floors, EPA's approach for this final rule is as follows. While commenters suggested using values less than the MDL, such values have not been demonstrated to have been met during the corresponding test run. Therefore, EPA concluded that it is not

appropriate, for development of MACT floors, to use any value less than the MDL. EPA also disagrees with comments that emission levels at or near the MDLs are appropriate levels to use for standard setting without consideration of measurement imprecision, because the actual performance of sources may differ significantly from the measured values or the MDL. Accordingly, for the boiler and process heater source category, which includes many sources with emission levels at or near the MDL for the various pollutants, EPA concluded that measurement imprecision was a significant factor that should be included in the development of emission limits. To determine an appropriate methodology, EPA examined the contribution of test method measurement imprecision to the variability of a set of emissions data. One element of variability is associated with method detection capabilities and a second is a function of the measurement value. Measurement imprecision is proportionally highest for values measured below or near a method's detection level and proportionally decreasing for values measured above the method detection level.

The probability procedures applied in calculating the floor or an emissions limit inherently and reasonably account for emissions data variability including measurement imprecision when the database represents multiple tests from multiple emissions units for which all of the data are measured significantly above the method detection level. That is less true when the database includes emissions occurring below method detection capabilities and are reported as the method detection level values.

EPA's guidance to respondents for reporting pollutant emissions used to support the data collection specified the criteria for determining test-specific method detection levels. Those criteria insure that there is only 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. Because of sample and emissions matrix effects, laboratory techniques, sample size, and other factors, method detection levels normally vary from test to test for any specific test method and pollutant measurement. 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.⁵

Also in accordance with our guidance, source owners identified emissions data which were measured below the method detection level and reported those values as equal to the method detection level as determined for that test. An effect of reporting data in this manner is that the resulting database is truncated at the lower end of the measurement range (i.e., no values reported below the test-specific method detection level). A floor or emissions limit based on a truncated database or otherwise including values measured near the method detection level may not adequately account for measurement imprecision contribution to the data variability. That is, an emission limit set based on the use of the MDL to represent data below the MDL may be significantly different than the actual levels achieved by the best performing units due to the imprecision of the measurements. This fact, combined with the low levels of emissions measured from many of the best performing units, led EPA to develop a procedure to account for the contribution of measurement imprecision to data variability.

We applied the following procedures to account for the effect of measurement imprecision associated with a database that includes method detection level data. The first step was to define a method detection level that is representative of the data used in establishing the floor or emissions limit and that also minimizes the influence of an outlier test-specific method detection level value. We reviewed each pollutant-specific data set to identify the highest test-specific method detection level reported that was also equal to or less than the average emissions level (i.e., unadjusted for probability confidence level) calculated for the data set. We believe that this approach is representative of the data collected to develop the floor or 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 in the process is to calculate three times the representative

⁵ American Society of Mechanical Engineers, *Reference Method Accuracy and Precision (ReMAP): Phase 1, Precision of Manual Stack Emission Measurements*, CRTD Vol. 60, February 2001.

method detection level⁶ and compare that value to the calculated floor or emissions limit. If three times the representative method detection level were less than the calculated floor or emissions limit calculated from the upper prediction limit (UPL), we would conclude that measurement variability was adequately addressed because the measurement imprecision at that level is a consistent 10 to 15 percent. The calculated floor or emissions limit would need no adjustment. If, on the other hand, the value equal to three times the representative method detection level were greater than the UPL-based emission limit, we would conclude that the calculated floor or emission limit does not account entirely for measurement variability. If indicated, we substituted the value equal to three times the representative method detection level to apply as the adjusted floor or emissions limit. This adjusted value would ensure measurement variability is adequately addressed in the floor or the emissions limit.

In response to comments that EPA should have used the PQL, RL, or LOQ values in place of non-detect values, we disagree that use of those values is appropriate for calculating the MACT floors for two reasons. First, these terms are not defined statistically or consistently from method to method but are relatively arbitrary multiples (e.g., 3 times, 5 times, or 10 times) of the MDL. In some cases, a RL, LOQ, or PQL is a value determined based on a laboratory-specific procedure and not standardized by the method. We could not apply data arbitrarily adjusted or subject to laboratory-specific variables in establishing the floor. Second, we used a value equal to three times a representative MDL to compare with the floor and to adjust the applicable emissions limit, if necessary. We believe that using a value equal to three times the MDL sufficiently accounts for measurement uncertainty for the purposes of establishing compliance and there is no need to try to define or apply a PQL, LOQ, or RL for this purpose.

4. Instrument Span for CO

Comment: Many commenters stated that the reported data and limits for CO are within the error range of analyzers and CO CEMS. For Method 10, the calibrated analyzers have an error of ± 2 percent of the instrument span, with spans ranging from 50 parts per million (ppm) to 1000 ppm or greater. As such, at a minimum there is a potential error

of 1 ppm to 20 ppm (2 percent of 50 ppm and 1000 ppm, respectively) while the liquid and other process gas categories have floor limits set at 1 ppm. Similarly, commenters noted that CO CEMS have an allowable drift of 5 percent of the span, with similar span ranges as Method 10. Commenters questioned the technical feasibility of complying with such low limits given the range in span values and suggested that EPA should review the data and establish more appropriate limits in consideration of measurement precision concerns.

Response: EPA agrees with the comment that many of the CO measurements are within the error range of analyzers, and EPA has taken steps to mitigate the potential bias of such measurements. The resulting emission limits represent a level of performance that has been demonstrated to be achieved by the average of the best performing 12 percent of sources while considering variability introduced by imprecision of the CO analyzers. As explained below, our assessment indicated that the site-specific estimated measurement errors in some cases may be higher than some of the reported emissions levels. Therefore, for each emission test used in the MACT floor calculations we substituted the site-specific estimated measurement error for reported values below those values in order to ensure the quality of the data used to set the floors.

In response to the comments received, we reviewed the quality of the data relative to information provided for each emissions test. Method 10 is structured such that we can assess measurement data quality relative to the calibration span of the instrument (see <http://www.epa.gov/ttn/emc/promgate/method10r06.pdf> and <http://www.epa.gov/ttn/emc/promgate/method7E.pdf>). For example, the allowable calibration error, system bias, and drift requirements are directly proportional to the site-specific instrument calibration span (i.e., ± 2.0 percent of the calibration span value). For instrument calibration span values of 25 ppmv and less, the allowable calibration error, bias, or drift values are each ± 0.5 ppmv.

We can estimate the equivalent of the method detection level for a measurement with an instrumental test method (e.g., EPA Methods 3A, 6C, 7E, and 10) using a square root formula and these allowable data quality criteria. For example, in the case of a calibration span value of 25 ppmv, the square root formula (i.e., square root of the sum of the squares) would indicate a value of 0.9 ppmv. Consistent with the

methodology we applied for non-instrumental methods, discussed in the previous comment response where we established limits no less than 3 times the MDL in order to avoid a large degree of measurement imprecision, this estimated measurement error value would translate to a limit of 3.0 ppmv (rounded up from 2.7 ppmv). For tests done with calibration spans of greater than 25 ppmv, the corresponding estimated measurement error would be greater. For example, the estimated measurement error using the square root formula for a calibration span of 100 ppmv would be about 4 ppmv which would translate to a limit of 12 ppmv. For a calibration span of 1000 ppmv, the estimated measurement error would be 35 ppmv or a limit of about 100 ppmv.

5. Achievability of Limits

Comment: Several commenters were concerned that only small subsets of sources in each subcategory have emissions stack test data. These commenters added that less data means the pool from which the best performing 12 percent of the existing sources are drawn is smaller and, therefore, the actual number of sources used to determine the MACT floor is smaller. The commenters suggested that EPA should collect more data or provide assurances that the limited available data are representative for each subcategory. Commenters suggested that EPA could supplement testing data with "emissions information" such as fuel records, production records and associated emission factors, commercial warranties and guarantees.

Commenters raised concerns that existing units would have difficulty demonstrating compliance with the MACT floor limits. They suggested best performers with advanced air pollution control technologies should not be required to install additional add-on equipment to meet the emission limits. Commenters requested that EPA assess how many existing boilers and process heaters in each subcategory will be able to meet the standards without taking any further control measures. Several commenters contacted manufacturers regarding a retrofit project for their boilers and process heaters and they noted that manufacturers were unwilling to guarantee a retrofit would meet the limits.

Similarly, commenters raised concerns that new units would have even more difficulty demonstrating compliance with the MACT floor limits. These commenters had difficulty identifying a single source whose emissions testing data demonstrated they could achieve all of the MACT

⁶ *Ibid.*

floors for new sources in combination. Several commenters contacted boiler and process heater manufacturers; all were unable to offer commercial emissions guarantees that a new unit would meet the proposed limits. Some commenters raised concerns about the impacts of these stringent new unit floors including: Deterring sources from upgrading to new boilers as efficiency gains provided by a new unit would be offset by extensive controls and threatening fuel diversity.

Some commenters expressed concern that EPA had not properly evaluated whether there are technically feasible means of achieving the MACT floors. The commenters contended that the approach does not identify reasons why best performing sources achieve emissions levels reflected in the test data and they suggested that the intent of the MACT floor standard setting process is to discover effective control techniques so that other performers in the source category could emulate those techniques, reduce their emissions, and achieve similar emission levels. Commenters added that EPA has not adequately considered air pollution control device (APCD) conflicts with one another or compatibility of controls on certain boilers. Additionally, choosing to optimize controls for one pollutant may preclude optimization of controls for another pollutant e.g., minimizing CO in the combustion system is opposed to minimizing NO_x in most boiler burners.

Response: As mentioned elsewhere in this preamble, EPA is required to establish MACT floor levels based on emissions limits achieved by sources for which emissions information is available to the Administrator. EPA has revised the proposed MACT floors as well as the proposed subcategories, as explained above. EPA also examined several ways in which it might be able to use other types of emissions information in addition to actual emissions measurements. However, EPA concluded that there was no appropriate method of using different types of information in a manner that could be incorporated into the variability analyses. EPA first assessed the potential for estimating emissions for sources that lacked actual emissions data through the use of emission factors. However, the emission factors lack any degree of variability. Therefore, the use of such data in this rulemaking would have distorted the data variability in many cases, leading to standards that were more stringent than those developed using emissions data only and that likely underestimated actual variability. EPA also considered

whether it could otherwise estimate emissions of sources that did not provide emissions data. However, EPA concluded that such estimations were not possible without the development of a technically appropriate approach to evaluate relevant information, and commenters did not provide any such approaches. EPA's approach provides MACT floors that are consistent with the requirements of section 112, because the floors are based on the average emissions performance of the best performers for which the Administrator has emissions information that is appropriate to use in setting the floors.

EPA agrees with commenters who note that many of the data sets are small. However, stakeholders were encouraged to provide additional data, and EPA significantly revised some of the proposed emission limits based on new test data. We received little or no additional data for some subcategories for which data sets were small at proposal. For all data sets, the final emission limits are based on the available data and reflect EPA's assessment of variability. Moreover, after consideration of the comments on the achievability of the emission limits, EPA performed additional analyses and detailed examinations of the data and developed revised limits that are based on what has been demonstrated to be achieved in practice. As described in more detail in the docket memorandum entitled "Revised MACT Floor Analysis (2011) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source," EPA has made adjustments to treatment of non-detect values, the statistical methodology, and monitoring requirements, and also incorporated new data and data corrections into our analyses. Accordingly, the final emission limits better reflect the performance of the MACT floor units than the proposed limits. EPA notes that for each subcategory, there are existing units that are meeting the MACT floor limits or are expected to meet the limits through application of available control technology.

Finally, in response to comments about low CO limits conflicting with a unit's ability to meet NO_x requirements, EPA does not have specific information on the NO_x limits and NO_x emissions for most of the units that will be subject to the standard. However, the CO limits have been revised as discussed elsewhere in this preamble, and compliance is based on a full load test, while periods of startup and shutdown are subject to a work practice standard. To the extent that units cannot meet the

CO floor and maintain NO_x at the required level, oxidation catalysts can be used to reduce CO without an increase in NO_x. EPA has included costs for these controls for many units in the cost analysis, although data on NO_x requirements were not sufficient to allow NO_x to be part of the analyses. Commenters did not provide any data supporting claims that any of the other emission limits or projected control devices would interfere with a source's ability to meet any of the other emission limits.

6. Comments on Technical Approaches

Comment: Several commenters offered suggestions for adjusting the treatment of data from common stacks. Commenters suggested that it is improper to count the data twice if two boilers, in the same subcategory, exhaust through a common stack. A test conducted on the common stack does not represent the actual emissions from a single boiler, but rather reflects emissions from the combined simultaneous operation of the two boilers and their associated control device(s). The commenters contended that it is impossible to claim the test result would be exactly the same for each boiler and they added that if a common stack test turns out to be in the lowest 12 percent in a subcategory, counting it twice distorts the average of the best performers and skews the variability calculations. Commenters also noted that it is also not appropriate to divide emissions evenly between each boiler. Instead these commenters suggested that EPA use the data from common stacks only a single time in the MACT floor ranking and UPL calculations.

Response: EPA's current approach is a reasonable approach for comingled emissions, particularly in light of the limited dataset available for some subcategories, because EPA can not accurately separate the fraction of the emissions that came from the combustion units and process emission points that are comingled in the same stack. Applying the emissions equally to multiple units exhausting through a common stack accurately represents the emissions of those units on average. Further, although the use of a data point twice may dampen variability, the inclusion of an extra unit in the floor has the opposite effect on the overall emission limit by increasing the denominator of the floor calculation. Either method could be used, but the results would not differ significantly. Furthermore, for existing sources, MACT cannot be less stringent than the average emission limitation achieved by

the best performing 12 percent of existing sources (for which emission information is available). If EPA ignored boilers that exhaust through a common stack, it would be ignoring available emissions information that is relevant to setting the MACT floor standards.

Comment: Some commenters raised concerns that the MACT floor methodology doesn't adequately address the inherent variability with respect to operating conditions and control device performance. Operational variability can include warm-ups, shutdowns, load swings, and variations in fuel quality. They contended that emissions data relied upon in the proposal were produced during reference method performance testing under very limited operating conditions and with a very limited variation in potential fuel quality. Other commenters raised concerns that EPA has not properly acknowledged the impact of fuel quality on emissions. One commenter urged caution to EPA when considering variability to generate compliance margins that are palatable to industry; suggesting that this concept is not incorporated in the statute.

Response: EPA is mindful of the need to account for sources' variability in assessing sources' performance when developing technology-based standards. EPA reviewed subcategory floor calculations in light of these comments and believes that the two-step MACT floor analysis process adequately addresses: (1) Performance testing variability and (2) fuel analysis variability estimations. EPA revised the MACT floor calculations in light of data submitted during and after the public comment period and also modified the approaches used at proposal for various aspects of the floor calculations.

EPA first took fuel into consideration, to the extent it is reflected in differences in boiler design, when we divided the source category into subcategories. EPA is aware that differences between given types of units, and fuel, can affect technical feasibility of applying emission control techniques, and has addressed this concern in the final rule. For a fuel based pollutant, such as PM, performance testing must be conducted under representative full load operating conditions, which, along with the parameter monitoring requirements, provides an assurance that the standards are being met at all times. For Hg and HCl, we modified the fuel based variability analysis in consideration of comments received on this approach. The first modification to the analysis was the introduction of a solid fuel subcategory, which includes any unit burning at least 10 percent, on an

annual heat input basis, of any coal, fossil solid, biomass, or bio-based solid fuel. Given the wide variety in fuel types that compose the floor, the statistical analysis accounts for some of the inter-unit variability for different fuel types identified to be in the floor. The second modification was the development of a fuel variability factor (FVF). The FVF calculations were similar to the calculations used at proposal, but they were simplified to remove the control efficiency calculation and the method for identifying outliers in the data was also adjusted. The revised FVF analysis calculated a ratio for all fuel analysis data points for units in the top 12 percent for existing units and the top performing unit for new units in each subcategory. This ratio compared the reported fuel analysis data, converted to units of lb/MMBtu, to the emission test outlet data, converted to units of lb/MMBtu, during the stack tests. At proposal we conducted an outlier analysis of only the maximum ratios for each unit, but we revised the outlier analysis to consider all of the ratios from top performers within each subcategory. We then defined and identified outliers using the test of 3 times the standard deviation and 3 minus the standard deviation for all of the ratios in the subcategory. After removing outliers, the remaining maximum ratio for each subcategory was identified and multiplied by the 99 percent UPL.

For a discussion of how EPA considered other non-fuel variability operations, such as boiler load, see response to the comments provided under "What did we do with the CO Limits".

Comment: Several commenters argued that it is inappropriate to rank units according to the minimum stack test since any boiler can experience a good compliance test if conditions are favorable. Many of these commenters suggested that EPA should instead rank the data on the average of all stack tests. Another commenter suggested that the different emission levels achieved by different sources are just differences in performance and basing the ranking on the average would be more appropriate. This commenter suggested that at a minimum, the data used to rank and the data used as inputs into the MACT floor upper prediction limit calculation should be consistent.

Response: In this final rule, EPA has reasonably determined that the best-controlled source is the source with the lowest stack test. EPA selected the lowest stack test as a measure of best performer because many units had only

a single test available, and the comparison of average performance from two or more tests is not directly comparable to a single test measurement. However, all emission tests of acceptable quality were used to assess variability. As such, all data were considered in the floor analyses. EPA recognizes that each stack test data point represents a true assessment of the emissions for a combustor at a given point in time. However, where units had more than one test available, EPA also considers these other tests to be representative of the unit and relevant to assess run-to-run and test-to-test variability in the MACT floor UPL calculation. EPA did screen and remove certain test data from the MACT floor calculations if that data were not deemed representative of current operating conditions.

7. Statistical Approach

There were several comments made on specific aspects of the statistical variability analysis including suggestions for the appropriate confidence interval, appropriate statistic, and EPA's methods for determining the distribution of the dataset. The specific comments and EPA responses are outlined below.

Comment: Industry, industry representatives, and environmental advocacy groups had different perspectives on the appropriateness of the proposed 99 percent UPL. Commenters from environmental advocacy groups requested a lower UPL with suggestions ranging between 50 to 95 percent. One commenter stated that EPA over-counts for the potential for future variability by using the 99 percent UPL for the entire data set and it does not adequately account for all variability, such as how unit maintenance and operator training may limit upward variability's effect on emission levels, and requests that EPA explain and justify the selection of the 99 percent UPL as opposed to the 90 or 95 percent UPL. Another commenter stated that most statistical analyses use 90 or 95 percent confidence intervals and prediction intervals. The commenter also claimed that 99 percent is overly conservative and results in twice as much HAP emissions and reduced health benefits compared to a lower UPL. Consequently the commenter stated a lower UPL would better withstand judicial review. One commenter mentioned that there is precedent for setting limits based on the 90th percentile and cited a 2006 analysis where EPA determined the best demonstrated technology, which found Hg reductions based on 90th percentile

and deemed the 90th percentile “reasonable” because of how compliance was to be determined and the high Hg content of the fuel used when the emissions data were collected. These commenters also suggested that EPA did not provide adequate rationale for selecting the 99th percentile instead of the 50th. These commenters noted that civil enforcement of environmental standards is based on a “preponderance of the evidence” which merely requires that a violation be more likely than not.

Commenters from industry and industry representatives advocated for a higher UPL. Commenters requested that EPA increase the UPL to 99.9 percent in order to better encompass unit emissions variability and represent a manageable risk. Industry, like environmental advocacy groups, also requested that EPA take into account operator training and its effect on emissions. The commenters claimed that operators are compelled to set emissions targets lower than limits to create a compliance margin which helps avoid violations and their consequences. Commenters also cited recent consideration of a 99.9 percent UPL in the proposed HMIWI MACT rule. Commenters claimed that since the HMIWI database consisted of a small dataset, it was unlikely full variability was observed and thus EPA had no valid statistical basis for the decisions to use 99 percent in the final HWIMI rule. The commenters suggested similar data limitations in the boiler dataset and argued that the 99.9 percent UPL should be used to allow more of a margin for all operating conditions and sample collection variation due to the limited data for the boiler MACT rule.

Response: In this final rule, EPA has reasonably determined that 99 percent UPL is appropriate for fuel based HAP, and dioxin/furan, and a 99.9 percent UPL is appropriate for CO. For fuel-based HAP the 99 percent confidence level is consistent with other recent rulemakings. See 75 FR 54975. Many of the subcategories had limited data to establish the MACT floor calculations and EPA determined it was inappropriate to use a confidence level lower than 99 percent to set the standard because doing so would result in limits that the best performers would be expected to exceed, while this final rule requires that units meet the limits at all times. Finally, for the fuel-based pollutants, there are well established control measures currently used on units in the source category (fabric filters for PM and Hg and wet or dry scrubbers for HCl) that serve to mitigate, to some degree, the variability in emissions that can be expected. Given

this additional consideration for fuel-based HAP, but recognizing the emission limits must be met at all times yet are based on short term stack test data, EPA selected the 99 percent confidence level. A lower confidence level would result in emission limits that even the best performing sources would be expected to exceed.

For CO, EPA considered several comments from industry and States, which provided both quantitative and qualitative comments on how CO emissions vary with load, fuel mixes and other routine operating conditions. After considering these comments EPA determined that a 99.9 percent confidence level for CO would better account for some of these fluctuations. While a good deal of CO data are available, at least for some of the subcategories, the data show highly variable emissions that can result from situations beyond the control of the operator, such as fuel moisture content after a rain event, elevated moisture in the air, and fuel feed issues or inconsistency in the fuel. The higher confidence level selected for CO is intended to reflect the high degree of variability in the emissions. For dioxin/furan, we also are maintaining the 99 percent UPL. Although much of the uncertainty associated with dioxin/furan testing will be mitigated by the requirement in EPA Method 23 to report non-detect values as zero for compliance purposes, the dioxin emission limits remain quite low and the 99 percent UPL provides a high degree of confidence that the best performing units will be able to meet the standards.

Comment: Several commenters also addressed concerns with how EPA determined the distribution of the dataset. Many commenters stated that normal distribution theory has been incorrectly applied to positively skewed or log normally distributed emissions data. Based on this, commenters claimed that sample means, and consequently the 99 percent UPL calculation, were incorrectly determined. Commenters suggested that sample means should be computed based on the arithmetic mean of lognormal distribution. One commenter requested that EPA consider using non-normal distributions or non-parametric methods in the analysis. Two commenters noted that the technique used by EPA based on logarithmic transformation underestimates the prediction limit for the mean and requested that EPA use the 2004 Bhaumik and Gibbons procedure for computing the UPL for log-normally distributed data. Three commenters

stated that EPA is not following its own guidance document, *Data Quality Assessment: Statistical Methods for Practitioners EPA QA/G-9S*, for determining whether or not a data set is normally distributed and should explain the reasons for not doing so. The commenters then go on to request that EPA follow its guidance documents which recommend use other tests aside from the skewness and kurtosis tests when data are limited or if critical test values are not available.

Response: EPA appreciates the detailed suggestions for alternative approaches to determine the dataset and it has revised its default selection of data distributions consistent with its guidance document *Data Quality Assessment: Statistical Methods for Practitioners EPA QA/G-9S*. This document indicates that most environmental data are lognormally distributed, so EPA has modified its assumptions when the results of the skewness and kurtosis tests result in a tie, or when there are not enough data to complete the skewness and kurtosis tests. Some of the commenters suggested that more advanced tests are necessary to determine the dataset, such as the Shapiro-Wilkes test. These tests need a sample size of 50 or more, and would not be appropriate for many of the small sample sizes used to compute the MACT floor UPL.

With respect to the methods used to compute the UPL for a dataset that is determined to be lognormally distributed, EPA also considered the commenters suggested revisions to the calculations in order to avoid skewing the UPL by calculating the UPL of an arithmetic mean instead of the UPL of a geometric mean. To adjust the calculation EPA considered a scale bias correction approach as well as a new UPL equation based on a Bhaumik and Gibbons 2004 paper, which calculates “An Upper Prediction Limit for the Arithmetic Mean of a Lognormal Random Variable”. Given data availability, EPA selected the Bhaumik and Gibbons 2004 approach which addresses commenters concerns with the proposed computations.

Comment: Several commenters suggested alternatives to the UPL statistics such as upper tolerance limit (UTL), upper limit (UL) and upper confidence limit (UCL). Several commenters stated that EPA’s UPL calculation was flawed and did not fully account for variability. Commenters then suggested that if the proposed UPL approach was maintained EPA should adopt the modified UPL equation in the Portland cement NESHAP. Commenters argued that this statistic would

represent floors achieved in practice and account for total variability instead of EPA's proposed UPL statistic based on sample variability. Several commenters claimed the data set was limited and suggested that EPA should use the UTL when data available do not represent the entire population. One commenter claimed that the upper UCL used in the HMIWI MACT rule was not a true prediction limit because it did not adjust the standard deviation for the number of test runs in the future compliance average and it should not be used in the boiler MACT rule.

Response: EPA considered these comments and reviewed each of the separate statistics. Because statistics is a tool and many statistical approaches could be considered valid, EPA considered the comments and adjusted the approach used to provide a reasonable and technically correct statistical methodology. MACT floors for existing sources must reflect the average emission limitation achieved by the best-performing 12 percent of existing sources. As explained below, only the UCL and UPL adequately get at the notion of average emissions. Use of the UPL is also consistent with other recent rulemakings. See 75 FR 54975.

In general, confidence intervals are used to quantify one's knowledge of a parameter or some other characteristic of a population based on a random sample from that population. The most frequently used type of confidence interval is the one that contains the population mean. Given this definition, the 99 percent UCL represents the value which we can expect the mean of the population to fall below 99 percent of the time in repeated sampling. Whereas a confidence interval covers a population parameter with a stated confidence, that is, a certain proportion of the time, there is also a way to cover a fixed proportion of the population with a stated confidence. Such an interval is called a tolerance interval. Confidence limits are limits within which we expect a given population parameter, such as the mean, to lie. Statistical tolerance limits are limits within which we expect a stated proportion of the population to lie. Given these definitions, the 99 percent UTL represents the value which we can expect 99 percent of the measurements to fall below 99 percent of the time in repeated sampling. In other words, if we were to obtain another set of emission observations from the five sources, we can be 99 percent confident that 99 percent of these measurements will fall below a specified level. Since you must calculate the sample percentile, and the sample sizes for the boiler MACT floor

data are small, the 99th percentile is underestimated. The UTL should only be used where one can calculate a sample percentile, e.g., where there is a sample size of at least 100, and we do not have that many sources represented in any MACT floor.

In contrast to a confidence interval or a tolerance interval, 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 the independent sample of size n from the same population. Finally, the upper limit (UL) is roughly equivalent to the percentile of the actual data distribution for the sample. The UL does not have a robust statistical foundation. Basically, the UL formulation assumes that the data: (1) Represent the population rather than a random sample from that population, and (2) are normally distributed. The data used to develop the MACT floors for this rule do not represent the entire population for any subcategory, and most of the data sets are not normally distributed. For these reasons, EPA concluded that it is not appropriate to use the UL in setting the MACT floor limits.

Comment: Some commenters suggested that EPA's UPL approach fails to accomplish predicting the level of performance achieved by the best performing sources under all operating conditions, not because of a poor statistical framework but because of an inadequate database. These commenters added that as a result, the inputs into the UPL equations are not representative of a distribution of values that reflect all operating conditions.

Response: Section 112(d) of the Act requires EPA to base MACT floor standards for existing sources on the average emission limitation achieved by the best performing 12 percent of existing sources for which EPA has emissions information. EPA has incorporated new data and data corrections received during the public comment period. EPA also has considered the requests for further subcategorization of the source category in light of limits on the dataset that caution against over-partitioning of the database. The revised analysis is based on all emission stack test data of appropriate quality available to EPA,

and the UPL approach provides as complete a picture of variability as possible given the limited data available.

Comment: Some commenters questioned whether the statistical approach met EPA's legal obligations under Section 112 of the CAA. One commenter stated that in order to withstand judicial review, the UPL should be calculated based on the best 6 percent of sources instead of the best 12 percent in order to establish a floor that would require 94 percent of sources to reduce emissions. One commenter stated that the courts did not endorse the proposed UPL procedure and that its appropriateness should be reviewed. The commenter goes on to say that on a statistical and technical basis, the UPL procedure is antithetical to the instruction in Section 112(d)(3)(A) and contradicts the strong endorsement of the high floor implementation as the best reading of the statutory language.

Response: While the commenter is correct that the entire MACT floor data pool was used in the calculation of the UPL, EPA notes that statistics is a tool that is used to estimate variability and it is entirely appropriate to consider the variability within the best forming 12 percent of sources in developing emission limits based on the average performance of those sources. As far as the concept that the floors should require 94 percent of the sources to reduce emissions, that is not what is required by the statute. Rather, the statute requires that the MACT floor standards for existing sources be no less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources for which EPA has emissions information. For example, if a category had 100 units and the performance of the best 50 of those units was the same, the emission limits would be based on those 50 units and they all would be projected to meet the limits. While this is a hypothetical scenario, it illustrates that there is no specific percentage of sources that must reduce emissions in order for the MACT floor limits to be consistent with the statutory requirement.

Comment: One commenter suggested that EPA should incorporate different statistical methods according to the amount and type of data available in each subcategory instead of a one-size-fits-all approach. This commenter also suggested that the approach taken by EPA must be validated by looking at the result it creates and examining whether the end result is reasonable. The commenter suggested applying a simple test to identify whether the resulting

floor requires a substantial majority of each subcategory to make some degree of emission reduction.

Response: EPA has revised its statistical approach to include a mixed use of confidence levels, as discussed above, as well as a mix of statistical tools to consider the distribution of the datasets and what types of data are used as inputs into the floor analysis. For example, the MACT floor computations for Hg emissions from liquid fuel units were modified to consider data from both fuel analysis and stack test results. EPA appreciates the suggestion for validating the results of the statistical computations and has determined that the final floor levels require a significant number of sources to make some degree of emission reduction. However, EPA also notes that the number of sources that will need to achieve some degree of emissions reduction from current levels is not the statutory basis for establishing emissions standards under section 112(d), as noted above.

Comment: One commenter representing manufacturers of monitoring and control technologies suggested that statistical variability should not be incorporated into the floor computations for CO and Hg. This commenter suggested that EPA base the floors on the straight averages of each data set.

Other commenters suggested that emissions variability is not statistical but instead based on different operating conditions of individual units. The commenters added that the variability of each unit should be averaged based on individual units and then used to establish UPL calculations instead of assessing a UPL based on individual tests or test runs.

Response: The UPL calculation is a statistical formula designed to estimate a MACT floor level that is equivalent to the average of the best performing sources based on future compliance tests. If we did not account for variability in this manner and instead set the limit based solely on the average (mean) performance, then these units could exceed the limit half the time or more. The MACT floors for existing sources must reflect the average emission limitation achieved by the best-performing 12 percent of existing sources. Therefore, it is appropriate to consider statistical variability in order to ensure that units could meet the floors at all times. EPA agrees with the commenter that the variability of emissions is not solely statistical, but also represents some operational variability that may occur between different tests at the same unit (intra-unit variability) as well as different tests

at different units (inter-unit variability) in the floor. Since the floor calculations represent the average of the best-performing 12 percent of existing sources, it is reasonable for EPA to use an appropriate statistical analysis to assess the impact both intra-unit and inter-unit variability have on the emissions profiles.

8. Alternative Units for Emission Limits

Comment: Several commenters from industry, State agencies, and environmental non-governmental organizations submitted a variety of alternatives to the concentration-based and mass-based MACT floor limits. Some commenters suggested emission reductions or removal efficiencies. These commenters cited regulatory precedence for a percent reduction limit in 40 CFR part 60 subpart Db, the New Source Performance Standards for Industrial, Commercial Institutional Boilers as well as New Source Performance Standards and Emission Guidelines for Large and Small Municipal Waste Combustors (40 CFR part 60 subparts Ca, Cb, Ea and Eb). Several other commenters suggested that EPA adopt an alternative output-based emissions standard to promote boiler efficiency improvements as a pollution prevention technique. One commenter called attention to several previous examples of output-based standards in recent air regulations, including the New Source Performance Standard for Electric Utility Steam Generating Units (40 CFR part 60 subpart Da) which includes an output-based emissions standard for Hg, PM, SO₂, and NO_x as well as the New Source Performance Standard for Industrial Commercial Institutional Boilers (40 CFR part 60 subpart Db) which includes an output-based emissions standard for NO_x. This commenter also provided examples of output-based emissions regulations in 12 states, including 4 that regulate non-electricity thermal output, such as from combined heat and power systems. Many commenters encouraged EPA to investigate opportunities to develop and implement output-based emissions standards for ICI facilities. Some commenters tied in the appropriateness of output-based standards to the Agency's other pollution prevention techniques included in the proposal, such as the energy assessments. The commenter added that by providing an output-based regulatory option, the user will have further incentive to implement energy efficiency opportunities identified during the energy assessment.

Response: With respect to the commenters' request for the development of percent reduction standards, sufficient data were not available to determine the percent reduction from the best performing units. In order to determine such standards, we would need emissions data from testing conducted at both the APCD inlet and outlet for the best performing sources, or at least for a reasonable number of best performing sources. However, we only have APCD inlet and outlet data for one pollutant (PM) for two subcategories, and based on this overwhelming lack of data available to calculate percent reduction standards, EPA did not pursue this option. We do agree with the commenters that output-based standards would provide incentives for implementation of energy conservation measures identified in an energy assessment. This final rule includes a compliance alternative that allows owners and operators of existing affected sources to demonstrate compliance on an output-basis. This alternate output-based limit will promote energy efficiency in industrial, commercial, and institutional steam-generating facilities, and are equivalent to the MACT emissions limits that are in heat-input format. EPA has established pollution prevention as one of its highest priorities. One of the opportunities for pollution prevention lies in simply using energy efficient technologies to minimize the generation of emissions. Therefore, as part of EPA's general policy of encouraging the use of flexible compliance approaches where they can be properly monitored and enforced, we are including alternate output-based emission limits in this final rule. The alternate output-based emission limits provide sources the flexibility to comply in the least costly manner while still maintaining regulation that is workable and enforceable. We investigated ways to promote energy efficiency in boilers by changing the manner in which we regulate flue gas emissions. The alternate output-based emission limits further this goal without reducing the stringency of the emissions standards.

Traditionally, boiler emissions have been regulated on the basis of boiler input energy (lb of pollutant/MMBtu heat input). However, input-based limitations allow units with low operating efficiency to emit more of each pollutant per output (steam or electricity) produced than more efficient units. Considering two units of equal capacity, under current regulations, the less efficient unit will emit more

pollutants because it uses more fuel to produce the same amount of output (steam or electricity) than a more efficient unit. One way to regulate mass emissions and encourage plant efficiency is to express the emission standards in terms of output energy. Thus, output-based emission standards provide a regulatory incentive to enhance unit operating efficiency and reduce emissions. An example of such an output-based standard is the NO_x standard under the New Source Performance Standards (subpart Da) for electric utility boilers.

The criteria used for selecting a specific output-based format were based on the following: (1) Provide flexibility in promotion of plant efficiency; (2) permit measurement of parameters related to stack emissions and plant efficiency, on a continuous basis; and (3) be suitable for equitable application on a variety of facility configurations. The output-based option of mass of pollutant emitted per boiler energy output (lb/MMBtu energy output) meets all three criteria. The majority of ICI boilers produce steam only for process operation or heating and, in this case, the energy output of the boiler is the energy content of the boiler steam output. For those ICI boilers that supply steam to generate, or cogenerate, electricity, the boiler's energy output can include both electrical and thermal (process steam) outputs. There are also some industrial boilers that only generate electricity. Technologies are readily available to measure these energy outputs, and they currently are measured routinely in many industrial plants. Therefore, emission limits based on this format can be applied equitably on a variety of facility configurations. Based on this analysis, an emission limit format based on mass of pollutant emissions per energy output was selected for the alternate output-based standards.

In the case of a boiler that produces steam for process or heating only (no power generation), the lb/MMBtu output-based emission limit is based on the mass rate of emissions from the boiler and the energy content in terms of MMBtu of the boiler steam output. At cogeneration facilities (also known as combined heat and power (CHP)), energy output includes both electricity and process steam. The steam from the boiler is first used to generate electricity. The thermal energy (steam) exiting the electricity generating equipment is then used for a variety of useful purposes, such as manufacturing processes, space heating and cooling, water heating, and drying. The electricity output and the useful energy

present in the steam exiting the turbine must both be accounted for in determining the overall energy output from the boiler and converted to a common basis of lb/MMBtu consistent with the output-based standard for steam-only units.

The efficiency and associated environmental benefits of CHP result from avoiding emissions from the generation of electricity at a central station power plant. The avoided emissions at most times are from a less-efficient unit that consequently also has higher emissions. Consequently, the electricity output of the CHP facility in kWh should be valued at the equivalent heat rate of the avoided central station power, nominally 10,000 Btu/kWh. Therefore, the lb/MMBtu output-based emission limit used for compliance with a CHP boiler is based on the mass rate of emissions from the boiler and a total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kWh generated (10 MMBtu per MWh).

Compliance with the alternative output-based emission limits would require continuous measurement of boiler operating parameters associated with the mass rate of emissions and energy outputs. In the case of boilers producing steam for process use or heating only (no power generation), the boiler steam output flow conditions would have to be measured to determine the energy content of the boiler steam output. In the case of CHP plants, where process steam and electricity are output products, methods would have to be provided to measure electricity output and the flow conditions of the steam exiting the electrical generating equipment and going to process uses. These conditions will determine the energy content of the steam going to process uses. Instrumentation already exists in many facilities to conduct these measurements since the instrumentation is required to support normal facility operation. Consequently, compliance with the alternate output-based emission limits is not expected to require any additional instrumentation in many facilities. However, additional signal input wiring and programming is expected to be required to convert the above measurements into the compliance format (lb/MMBtu energy).

Since the June 4, 2010, proposal, we obtained steam data (flow, temperature, and pressure) from the best performing units that made up the MACT floor at proposal. In determining alternate

equivalent output-based emission limits, we first determined for each of the best performing units the Btu output of the steam and then calculated the boiler efficiency and then calculated the boiler efficiency for each of the boilers having available steam/heat input data. Boiler efficiency is defined as steam Btu output divided by fuel Btu input. Next, we determined the average boiler efficiency factor for each subcategory from the best performing units in that subcategory. We then applied the average boiler efficiency factor to the final MACT limits that are in the current format of lb/MMBtu heat input to develop the alternate output-based limits. The efficiency factor approach was selected because the alternative of converting all the reported data in the database to an output-basis would require extensive data gathering and analyses. Applying an average boiler efficiency factor, based on the individual boiler efficiency of the best performing units, essentially converts the heat input-based limits to output-based emission limits.

The alternate output-based emission limits in this final rule do not lessen the stringency of the MACT floor limits and would provide flexibility in compliance and cost and energy savings to owners and operators. We also have ensured that the alternate emission limits can be implemented and enforced, will be clear to sources, and most importantly, will be no less stringent than implementation of the MACT floor limits.

B. Beyond the Floor

1. Energy Assessment Requirement

Comment: In the proposal preamble, we solicited comments on various aspects of the energy assessment requirement. The proposed standards included the requirement to perform an energy assessment to identify cost-effective energy conservation measures. Since there was insufficient information to determine if also making the implementation of cost-effective measures a requirement was economically feasible, we requested comment on this point. We also specifically requested comment on: (1) Whether our estimates of the assessment costs are correct; (2) is there adequate access to certified assessors; (3) are there organizations other than 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. The energy assessment requirement has been revised in this final rule and alternate equivalent output-based emission limits have been incorporated into this final rule as an alternative means of complying with the emission limits in final rule. The alternate output-based emission limits allow a facility implementing energy conservation measures that result in decreased fuel use to comply with that emission limit by applying emission credits earned from the implementation of the energy conservation measure.

Commenters stated that EPA should provide a clear, statutory-based definition of "Boiler," and the scope of the required energy assessment. Commenters also stated that if EPA includes an energy assessment requirement in this final rule, it should regulate only the emission source over which it has § 112 authority to regulate. The "boiler" logically includes the combustion unit (the emissions source) and closely associated equipment, from flame to last heat recovery. EPA should adopt this definition of "boiler system," which reflects the extent of its section 112 authority.

Commenters also recommended that an energy assessment previously conducted of a facility that has not had significant changes to the boilers and associated equipment should be acceptable for initial compliance. Energy performance of facilities strongly depends on equipment configuration, equipment performance, and fuels fired. If these do not change from the time an energy assessment was conducted to the time the Initial Compliance energy assessment report is submitted, the report would be representative of an accurate depiction of the facility.

Several commenters supported the use of energy assessments as a "beyond the floor" control measure and advocated for output-based standards (noting that such an approach is critically important to encourage CHP since input-based emissions regulations fail to credit CHP systems for their greater efficiency, reducing the incentive for CHP to be installed and used throughout U.S. industry). Moreover, since this final boiler rule will apply to a wide variety of manufacturing facilities in multiple sectors producing a variety of final products, normalizing pollutant output per useful energy output is a good way to ensure all affected facilities can be assessed on similar baselines. Several commenters also applauded recognition of energy efficiency measures to achieve

pollution reductions and encouraged EPA to continue to view energy efficiency investments favorably. Some commenters criticized EPA's failure to require implementation of findings of the energy assessments.

Response: We agree that EPA should provide a clear definition of what the energy assessment should encompass. However, we disagree that the energy assessment should be limited to only the boiler and associated equipment, and in fact the proposed rule included a broader scope. EPA has properly exercised the authority granted to it pursuant to CAA section 112(d)(2) which states that "Emission standards promulgated * * * and applicable to new or existing sources shall require the maximum degree of reduction in [HAP] emissions that the Administrator determines * * * 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 energy assessment requirement is squarely within the scope of this authority. 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 from the affected boiler, which would result in reduced fuel use. Reduced fuel use will result in a corresponding reduction in HAP, and non-HAP, emissions from the affected boiler.

We agree that the scope of the required energy assessment presented in the proposed rule needs to be clarified and we have done this in this final rule. In the proposed Boiler MACT, the intended scope of the energy assessment did extend beyond the affected boiler. The energy assessment included a requirement that a facility energy management program be developed. The energy assessment was intended to be broader than the affected boiler and process heater and included other systems or processes that used the energy from the boiler and process heater. We disagree that the scope of the energy assessment should be limited to the boiler and directly associated components such as the feed water system, combustion air system, fuel system (including burners), blow down system, combustion control system, and heat recovery of the combustion fuel gas. Including all of the energy using systems in the energy assessment can result in decreased fuel use that results

in emission reductions, the result articulated in 112(d)(2). We have included in this final rule a definition of what the energy assessment should include for various size fuel consuming facilities. We also have included a definition of the qualified assessors who must be used to conduct those energy assessments. We have clarified the requirement that the energy assessment include a review of the facility's energy management program and identify recommendations for improvements that are consistent with the definition of an energy management program. A definition of an energy management program that is compatible with the ENERGY STAR Guidelines for Energy Management and other similar approaches was added.

We also agree that a facility should be exempt from the requirement to conduct an energy assessment if an energy assessment has recently been conducted. We have revised the final rule to allow facilities to comply with the requirement by submitting an energy assessment that has been conducted within 3 years prior to the promulgation date of this final rule.

Comment: The principle arguments against an energy assessment requirement are: (1) EPA lacks authority to impose requirements on portions of the source that are not designated as part of the affected source, such as non-emitting energy using systems at a facility; (2) EPA has not quantified the reductions associated with the energy assessment requirement, therefore it cannot be "beyond the floor;" and (3) the bare requirement to perform an audit without being required to implement its findings is not a standard under CAA section 112(d).

Response: With respect to the first argument, we have carefully limited the requirement to perform an energy audit to specific portions of the source that directly affect emissions from the affected source. The emissions that are being controlled come from the affected source. The process changes resulting from a change in an energy using system will reduce the volume of emissions at the affected source by reducing fuel consumption and the HAP released through combustion of fuel. The requirement controls the emissions of the affected source and, as explained above, is within the scope of EPA's authority under section 112(d)(2).

With respect to the second argument, the energy assessment will generate emission reductions through the reduction in fuel use beyond those reductions required by the floor. While the precise quantity of emission reductions will vary from source to

source and cannot be precisely estimated, the requirement is clearly directionally sound and thus consistent with the requirement to examine beyond the floor controls. By definition, any emission reduction would be cost effective or else it would not be implemented.

Finally, with respect to the third argument, the requirement to perform the energy audit is, of course, a requirement that can be enforced and thus a standard. As noted, while we do not know the precise reductions that will occur at individual sources, the record indicates that energy assessments reduce fuel consumption and that parties will implement recommendations from an auditor that they believe are prudent. Therefore, the requirement to perform an energy assessment can both be enforced and will result in emission reductions.

We agree that EPA should provide a clear definition of what the energy assessment should encompass. However, we disagree that the energy assessment should be limited to only the boiler and associated equipment. EPA has properly exercised the authority granted to it pursuant to CAA section 112(d)(2) which states that "Emission standards promulgated * * * and applicable to new or existing sources shall require the maximum degree of reduction in [HAP] emissions that the Administrator determines * * * 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 from the affected boiler which would result in reduced fuel use. Reduced fuel use will result in a corresponding reduction in HAP, and non-HAP, emissions from the affected boiler. Reducing the energy demand from the plant's energy using systems can result in additional reductions in fuel use and associated emissions from the affected boilers. We agree that the scope of the required energy assessment needs to be clarified. However, in the proposed Boiler MACT, the intended scope of the energy assessment did extend beyond the affected boiler. The energy assessment did include a requirement that a facility energy management program be developed. The energy assessment was intended to be

broader than the affected boiler and process heater and included other systems or processes that used the energy from the boiler and process heater. We disagree that the scope of the energy assessment should be limited to the boiler and directly associated components such as the feed water system, combustion air system, fuel system (including burners), blow down system, combustion control system, and heat recovery of the combustion fuel gas. Including the facility's energy using systems and energy management practices in the energy assessment can identify measures that result in decreased fuel use and related emission reductions. We have included in this final rule a definition of what the energy assessment should include for various size fuel consuming facilities. We also have included a definition of the qualified assessors who must be used to conduct those energy assessments.

We also agree that a facility should be exempt from the requirement to conduct an energy assessment if an energy assessment had recently been conducted. We have revised this final rule to allow facilities to comply with the requirement by submitting an energy assessment that had been conducted within 3 years prior to the promulgation date of this final rule.

C. Rationale for Subcategories

Many commenters stated that EPA should have proposed more subcategories, while others believed that too many subcategories were proposed. Many different issues were raised, and some of the key issues that led to changes in the rule include: The need for a limited use subcategory for boilers that operate for only a small percentage of hours during a year; the unique suspension/grate design of units that combust bagasse; the need for a non-continental liquid fuel subcategory for island units that have limited fuel options and other unique circumstances; and the appropriate subcategory for mixed fuel units. The comments and EPA responses are provided below.

1. Limited Use Subcategory

Comment: Industry representatives and State and local governments argued that limited use units are significantly different from steady-state units and requested that they have their own subcategory. Commenters requested various thresholds for a limited-use subcategory including 10 percent annual capacity factor or 1,000 hours of operation per year. Several commenters stated that due to their function, limited use boilers spend a larger percentage of

time in startup, shutdown, or other reduced-efficiency operating conditions than either base-loaded or load-following (continuously operated) units. Operating more frequently in these conditions makes emissions profiles of limited use units very different from sources which operate in more efficient steady-state modes. Based on this, commenters claimed it would be technically infeasible for limited-use units to meet the proposed emission limits.

In addition to technical reasoning, commenters also submitted requests for a limited-use subcategory on the basis of regulatory precedent, citing the 2010 RICE MACT and 2004 vacated Boiler MACT. Several commenters requested a subcategory and work practices similar to those in the Stationary RICE NESHAP. Several other commenters also stated that the subcategory was warranted because it was included in the previous Boiler MACT rule. These commenters argued that EPA had not provided any justification for eliminating the subcategory in the proposed rule. Some of these commenters also stated that the recordkeeping requirements that were proposed in Section 63.7555(d)(3) for limited-use boilers and process heaters should be the only requirement for these units.

The majority of commenters that requested a limited use subcategory also requested for EPA to adopt a work practice standard for limited use units and not subject the subcategory to emissions testing or monitoring. Commenters argued that EPA has acknowledged that there is no proven control technology for organic HAP emissions from limited use units. Limited use units, such as emergency and backup boilers, cannot be tested effectively due to their limited operating schedules. Based on existing test methods, which require a unit to operate in a steady state, limited use units would have to operate for the sole purpose of emissions testing. One commenter claimed that the proposed rule performance testing would require, not including startup and stabilization, operating at least 15 additional hours of per year, or 24 hours per year if testing for all pollutants is required. Commenters also noted that because the operation of these units is neither predictable nor routine over a 30 day period, back-up boilers would not benefit from 30-day emissions averaging. Commenters argued that establishing numerical standards for limited use units is contrary to the goals of the CAA and will lead to creating

emissions for the sole purpose of demonstrating compliance.

Many commenters also mentioned the economic impacts of a numerical limit on limited-use units and requested work practice standards. Commenters stated that it would not be cost effective to install controls on units that operate at 10 percent capacity or less annually. They claimed that the additional controls would produce minimal emission reductions and would result in the shutdown of limited-use units.

Several commenters claimed that the current distinction between natural gas and oil-fired limited-use units is unnecessary, and that additional requirements for oil-fired units do not produce environmental benefits. Commenters recommended that EPA create a separate subcategory for limited use, oil-fired boilers and suggest that the work practice standard proposed for gas-fired boilers be applied in lieu of emissions standards for these units. Other commenters stated that the limited use subcategory should include new/reconstructed limited use units as well as existing units for all fuel categories. One commenter recommended a tiered approach and stated that for very limited use boilers, EPA should establish a standard with no additional controls or requirements, other than monitoring annual hours of operation. They defined very limited use as <500 hours of operation per year.

Response: EPA agrees that a subcategory for limited use units is appropriate for many of the reasons stated by the commenters. The fact that the nature of these units is such that they operate for unpredictable periods of time, limited hours, and at less than full load in many cases has lead EPA to determine that limited use units are a unique class of unit based on the unique way in which they are used and EPA is including a subcategory for these units in the final rule. The unpredictable operation of this class of units makes emission testing for the suite of pollutants being regulated impracticable. In order to test the units, they would need to be operated specifically to conduct the emissions testing because the nature and duration of their use does not allow for the required emissions testing. As commenters noted, such testing and operation of the unit when it is not needed is also economically impracticable, and would lead to increased emissions and combustion of fuel that would not otherwise be combusted. Therefore, we are regulating these units with a work practice standard that requires a biennial tune-up, which will limit HAP by ensuring

that these units operate at peak efficiency during the limited hours that they do operate.

2. Combination Grate/Suspension Firing

Comment: Several commenters requested EPA further subcategorize boilers and process heaters according to combustor design. Three industry and collective trade group representatives requested EPA consider adding a bagasse boiler subcategory. These commenters claimed that bagasse boilers are different from other biomass boilers based on both fuel type and boiler design. The commenter suggested four factors EPA should consider when establishing similar sources or subcategories: (1) Do the units in the category have comparable emissions; (2) are the units structurally similar in design; (3) are the units structurally similar in size; and, (4) are the units capable of installing the same control technology. The commenter elaborated on the fuel density and moisture of bagasse fuel and highlights the unique combustor design needed to heat and evaporate the moisture from the fuel using a combination of suspension and grate firing. Several commenters requested that EPA set separate subcategories for organic HAP (or CO) and for metal HAP and PM for bagasse boilers (between 48 to 55 percent moisture), suspension burners designed to burn dry biomass (defined as less than 30 percent moisture), suspension burners designed to burn wet biomass (greater than 30 percent moisture), and Dutch ovens.

One commenter also requested that the regulatory definition of bagasse boiler be altered to take into account that bagasse boilers are hybrid suspension and grate/floor-fired boilers uniquely designed to dry and burn bagasse. The commenter goes on to explain that the majority of drying and combustion take place in suspension and the combustion is completed on the grate or floor. The boilers are designed to have high heat release rates and high excess air rates which are to evaporate high fuel moisture content and this design impacts CO, PM, and organic HAP formation. Under the proposal, most bagasse-fired boilers would be categorized as "suspension burners/dutch ovens designed to burn biomass." However, the commenter claimed that the CO limit for this subcategory was driven largely by emissions data from units which fire dry biomass (*i.e.*, less than 20 to 30 percent moisture fuel) that do not need to undergo this initial drying process, since the fuel is already dry enough to combust. The commenter elaborated that emissions of organic

HAP and PM from these dry biomass suspension boilers are much different than boilers that must use a combination of suspension firing and grate firing in order to achieve complete combustion of a wet fuel such as bagasse.

One commenter went on to say that EPA has inappropriately subcategorized suspension burners/dutch ovens designed to burn biomass as a single subcategory. Hybrid suspension/grate-floor burners are designed such that the wet fuel first undergoes drying and then combustion in suspension within the furnace, with any remaining unburned fuel falling onto the grate to complete combustion. Another commenter also provided technical design elements to highlight the differences between dutch ovens, suspension burners, and the above mentioned hybrid suspension grate burners. This commenter indicated that dutch ovens have two chambers. Solid fuel is dropped down into a refractory lined chamber where drying and gasification take place in the fuel pile. Gases pass over a wall into the second chamber where combustion is completed. Dutch ovens are capable of burning high moisture fuels such as bark, but have low thermal efficiency and are unable to respond rapidly to changes in steam demand. On the contrary, suspension burners combust fine, dry fuels such as sawdust and sander dust in suspension. Rapid changes in combustion rate are possible with this firing method. This commenter added that some dutch oven units located at particleboard, hardboard, and medium density fiberboard plants were misclassified and there are less than 30 true dry-fired suspension burners in operation, and only a small handful of true dutch oven boilers.

Response: EPA agrees that for combustion-related pollutants (used as a surrogate for organic HAP emissions), the design differences for hybrid suspension grate boilers (also referred to as combination suspension/grate boilers) are significant, and that combustion conditions in these types of units are not similar to those in dutch ovens or true suspension burners that combust fine, dry fuels. Therefore, EPA has added a hybrid suspension grate boiler subcategory for CO and dioxin/furan emissions. However, the differences discussed by the commenters with respect to PM are less indicative of the design of the boiler and more indicative of the types of air pollution controls that are used. In keeping with the subcategorization approach being used for this final rule, these units, and all other solid fuel units, will be included

in a subcategory for units combusting solid fuels for PM, Hg, and HCl.

3. Non-Continental Units

Comment: Commenters from affected island refineries and trade groups representing the petroleum and refining sectors requested additional fuel oil burning flexibility in this final rule and stated that work practice standards are more appropriate for fuel oil burning at refineries and other remote locations without access to natural gas.

Commenters also submitted technical issues justifying the creation of a non-continental or remote location subcategory. One commenter stated that most oil combustion in the petroleum sector is in locations that are islands or in more remote parts of the United States. Island and remote facilities cannot physically access natural gas pipelines, making burning liquid fuels unavoidable. The option of crude oil shipments would be impractical because the ships are limited by size and what is manageable by load/discharge ports. The commenter also claims that in the time it would take a crude ship to arrive, the refinery would have produced the amount of crude in the shipment. Further, while some units at a facility are designed to burn refinery fuel gas, the fuel gas produced at a refinery is less than the energy required to operate the refinery. These non-continental facilities are also limited to the fuel quality provided by their nearby crude slate used in the refining process. That commenter goes on to say that these refineries produce their fuel, the HAP metals content of the fuel used (particularly residual fuel oil) is a direct result of the crude slate used on site. The commenter submitted trace metals from various crudes to show that the content varies substantially between crude oils being used on site.

Another commenter provided the following distinctions for non-continental units: A striking example of fuel system differences for non-continental units is daily variation in fuel gas production due to ambient temperature fluctuations between night and mid-day or resulting from tropical rainfall events, coupled with fin fan cooling systems that are used because of the lack of fresh water available in an island without freshwater lakes or streams. The fuel system experiences a large daily variation in refinery fuel gas due to changes in ambient air temperature. These changes occur as a day-night swing in the refinery or any time there is a significant rain storm. As the ambient air temperature decreases, the amount of propane, butane and heavier molecules in the fuel gas

decreases, as those compounds condense out. This results in a change in volume and composition (energy content) of the refinery fuel gas produced which, in the case of rainfall events, occurs very quickly and unpredictably. This temperature variation occurs more frequently than at a mainland refinery because: The method of cooling on gas compressors and distillation column overheads systems is ambient air fin fan coolers (water with cooling towers is not used like a stateside refinery because fresh water is not available other than by desalination); the refinery fuel gas system contains miles of aboveground piping (long lines are affected by rain and weather conditions); refinery fuel gas contains more propane and butane than would natural gas from a pipeline (which condense at closer to ambient temperatures than methane or ethane); the make-up fuel system for the refinery is not a natural gas pipeline as at a stateside refinery. A natural gas pipeline can handle changes in refinery fuel gas produced because natural gas delivery systems are usually large enough to handle changes. A temperature change of 10 to 15 degrees or a rain storm that quickly wets the air fin fans/piping will change the volume and composition (energy content) of the refinery fuel gas produced and also impacts CO emissions.

In addition to the technical limitations described above, one commenter cited other EPA air regulations that have provided separate standards or subcategories for non-continental units. For example, 40 CFR part 60 subparts Db and KKKK include separate standards for "non-continental" units and the 2010 CISWI proposal had a subcategory for smaller remote facilities because of inherent design and operating constraints.

Another commenter mentions that the inability to obtain natural gas removes the option of being able to burn only gaseous fuels as a compliance strategy and burning fuel oil as a supplemental fuel makes complying with this proposed MACT unfairly onerous.

Response: EPA agrees that the unique considerations faced by non-continental refineries warrant a separate subcategory for these units. However, data were only provided for CO and Hg, and, in the absence of data for the other pollutants, EPA is adopting the same limits that were developed for liquid units, because liquid units are the most similar units for which data are available. EPA assumed that while the commenter focused on changes in refinery gas, that the commenters concern was with liquid fuel-fired units

whose performance is impacted by the co-firing of refinery gas. Regardless, it is clear that the unique design of this type of unit warrants a separate subcategory because design constraints would not enable the sources to meet the same standards, particularly for CO, as stateside units.

4. Combination Fuel Units

Comment: Several industries and industry representatives in addition to some State and local governments argued that combination fuel units are significantly different from units in single fuel subcategories. These commenters focused on three types of combination fuel units. The first, which the majority of comments focused on, was biomass and coal co-fired units. Commenters stated that classifying units that burned 90 percent biomass in the coal subcategory if it fired at least 10 percent heat input coal penalizes and discourages the use of biomass. One commenter claimed that they were unaware of any available control technology with the capability of reducing emissions from its biomass-fired boilers from their current levels to the level proposed for the coal stoker subcategory. Commenters stated that in order to meet the organic HAP limits for coal, they would have to switch from biomass to more coal or abandon co-firing projects. According to the commenter this result was contrary to state Renewable Portfolio Standards and general national renewable energy policy.

The second type of combination unit commenters discussed was units that co-fire gas and liquid fuels. Many commenters argued that combination oil and gas fired units are of a completely different design than EPA contemplated in setting its standards and cannot be fairly included in the same subcategory with other dedicated gas or oil fired units. Commenters elaborated that the main design difference was due to combustion techniques which require the heater/boiler firebox configuration to compromise between the needs of oil fuel and gas fuel, making it impossible to maximize combustion efficiency or minimize NO_x emissions. Commenters also noted that these units were not considered in development of the MACT standards, and claimed that they are well known in the burner industry and referenced in standard literature.

The third type of combination unit, one commenter mentioned, was a subcategory for units co-firing biomass with any solid fuel. Commenters claimed that by failing to recognize the wide verity of fuel inputs and thus the variation in fuel quality (i.e., BTU and

moisture content) and emissions, EPA was penalizing facilities that use multiple fuel streams. The commenter went on to request that EPA establish emission limits that reflect the variation in fuels and fuel quality in these combination units.

Several commenters disagreed with the EPA statement that boilers are designed to burn only one fuel and that unit will encounter operational problems if another fuel type is fired at more than 10 percent heat input. Commenters stated that some boilers are specifically designed to burn a combination of fuels, and to burn them in varying quantities. Commenters elaborated that such boilers are not able to reach full load on any single fuel and that EPA has incorrectly presumed that all boilers are designed based on a primary fuel. Some commenters identified that many of the boilers used as the basis of the proposed MACT floor emission limits co-fire different fuel types. One commenter stated that if most units are designed to burn a primary fuel and will encounter problems if the 10 percent threshold is exceeded, then EPA has proposed MACT standards that will apply to boilers that by their nature are "encountering problems" due to their fuel mix. The commenter requested that EPA address this inconsistency.

Many commenters noted that emissions profiles vary with the fuel which made it very difficult to establish a typical emissions profile. Commenters also explained that combination fuel boilers must often adapt to process steam demands and thus experience frequent load swings and fuel input adjustments that cause significant variation in CO emission levels. Commenters also mentioned that control compatibility should be considered for multi-fuel boilers because they have inherently different control needs depending on the fuels being fired. Commenters went on to say that current limits are based on control equipment that is optimized for one HAP or fuel but the affect of other HAP and fuels or even another control would result in unknown performance and compatibility with other fuel types.

Several commenters also had concerns regarding enforcement and compliance of combination fuel units. One commenter requested that EPA more specifically address the "enforceability" of the "designed to burn" classification and more clearly consider the implications of the multi-fuel boiler operation on testing considerations. Another commenter stated that expressing limits as applicable to units "designed to burn"

certain fuels was problematic and should be changed to "permitted to burn" because a State permit could limit the type of fuels combusted at a unit that may have originally been designed to burn other fuel types. Other commenters claimed that the fuel subcategory should be determined by the actual quantity of fuel burned not what the unit is designed to burn. Some questions that commenters requested clarification on were: If compliance tests would be required under different fuel firing conditions, can units with CEMS switch limits depending on what fuel is being combusted, if "designed to combust" is not maintained would actual fuel burned or fuel the unit is permitted to burn determine the subcategory, what would the annual performance test be if in the middle of the year a unit goes from having burned only one type of fuel to only another type the rest of the year.

Several solutions were suggested for addressing combination boilers. Some commenters requested that combination boilers have their own subcategory. Several other industry commenters suggested that EPA modify the subcategory definitions and applicability so that combination fuel units burning more than 10 percent coal with biomass would be regulated under the coal subcategory for fuel-based HAP and units burning more than 10 percent biomass with coal would be regulated under the biomass subcategory for combustion-based HAP. A more general solution proposed, for all types of combination fuel units, was that if a facility combusts more than one fuel type, it must meet the lowest applicable emission limit for all of the fuel types actually burned. Some commenters also requested the development of a formula based approach similar to that of the boiler NSPS SO₂ limits that considers the mix of fuel fired rather than assuming one fuel dictates the emission limitations.

Some commenters were concerned that determination of MACT floor limits should be based only on data obtained while firing 100 percent of the affected fuel category and recommended that EPA either exclude all test runs where a unit was co-firing or adjust the data accordingly to remove the co-firing bias.

Response: In response to the variety of comments regarding combination fuel boilers, EPA has revised the subcategories in order to simplify implementation, improve the flexibility of units in establishing and changing fuel mixtures, promote combustion of cleaner fuels, and provide MACT standards that are enforceable and consistent with the requirements of

section 112. For the combination liquid and gas-fired units, while the commenters provided some insights on these units, the data available to EPA regarding any distinctions between these units and units designed to burn liquid only were insufficient to provide a justification for changing the approach for these units. For combined fuel units that combust solid fuels, due to the many potential combinations and percentages of solid fuels that are or can be combusted, for the fuel-based pollutants, EPA selected the option of combining the subcategories for solid fuels into a single solid fuel subcategory. For the fuel-based pollutants, this alleviates the concerns regarding changes in fuel mixtures, promotion of combustion of dirtier fuels, and the implementation and compliance concerns. For combustion-based pollutants (CO and dioxin/furan), we maintained the proposed subcategories and added a few additional subcategories, as discussed elsewhere in this preamble, based on public comment. One change we are finalizing is that to determine the appropriate subcategory, instead of considering whether the unit is designed to combust at least 10 percent coal as the first step (as proposed), the first step in determining the appropriate subcategory is to consider the percentage of biomass that is combusted in the unit.

The subcategories for the combustion-based pollutants are now determined in the following manner. If your new or existing boiler or process heater burns at least 10 percent biomass on an annual average heat input basis, the unit is in one of the biomass subcategories. If your new or existing boiler or process heater burns at least 10 percent coal and less than 10 percent biomass, on an annual average heat input basis, the unit is in one of the coal subcategories. If your facility is located in the continental United States and 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 coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the liquid subcategory. If your non-continental 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 coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the non-continental liquid subcategory. Finally, for the combustion-based pollutants, if your unit combusts gaseous fuel that does not

qualify as a "Gas 1" fuel, your unit is in the Gas 2 subcategory.

D. Work Practices

1. Gas 1 Work Practices

Comment: Several industry and industry trade group commenters expressed general support for the adoption of work practice standards for natural gas and refinery gas (Gas 1) fired boilers and process heaters. Many of these commenters stated that work practice standards will minimize HAP emissions in a cost effective manner.

Commenters, including industry representatives and one government agency, submitted several technical justifications that supported the proposed work practice standards for natural gas and refinery gas units. Many of these commenters stated that Gas 1 units contribute a negligible amount of the total emissions from the source category. One commenter stated that based on a review of air permits issued for natural gas-fired units over the last 10 years no HAP emissions were identified at rates which required the State to set emission limits. Further, many commenters indicated that no currently-available control technology or technique has been indentified to achieve numeric limits for natural gas units. Others went on to argue that tune-ups actually represent the only "floor" technology currently in use at boilers and process heaters in the Gas 1 subcategory. One commenter stated that design characteristics of these units, and hence the emissions-reduction potentials of annual tune-ups, vary widely and no single emission rate or even percentage of emission reduction could be translated into a numerical limit.

Several commenters argued that work practice standards were justified based on the technical infeasibility of emissions testing and the accuracy of testing results from gas units. These commenters stated that most of the emission test data were close to detection limits or in some cases indistinguishable from ambient air near the lowest detect levels, thus preventing the limits from being enforced or reliably measured. Others argued that the application of EPA test methods to measure emissions from natural gas units results in unreliable data given that the emissions are low and below what the test methods can detect, causing repeat tests or significantly lengthening the periods for the tests, which in turn increase the cost of testing.

On the contrary, one of the environmental advocacy group

commenters stated that EPA exempted natural gas-fired units from CO limits without any discussion or analysis. This commenter argued that nothing in the rulemaking docket showed that measurement would be technically infeasible and identified CO emission test results from over 160 natural gas-fired units in the NACAA database. Further, the commenter suggested that federal, State and local authorities have routinely required CO to be measured at gas fired units since CO is a criteria pollutant under the CAA.

In addition to technical reasoning, many industry and industry representative commenters also supported the adoption of work practice standards on the basis of legal precedent and authority under the CAA. Commenters stated that EPA derives its authority to use work practices in lieu of numeric emission limitations from two different statutory provisions: The narrowly construed provisions of 112(h) and the broad authority under 112(d) as defined in section 302(k). Additionally, one commenter stated that work practice standards for Gas 1 units are consistent with the D.C. Circuit's opinion in *Sierra Club v. EPA* on the Brick MACT standard, which provided guidance on the criteria EPA must meet to justify the application of section 112(h) work practices, only if measuring emission levels is technologically or economically impracticable.

Many commenters also cited economic justifications supporting the proposed work practices for Gas 1 units. These comments included claims that work practice standards avoid economic harm to the manufacturing sector, and they added that the cost to control each unit would be extremely burdensome with minimal benefits to the environment. These commenters suggested that any type of control beyond a tune-up would be a beyond-the-floor option and the complex controls needed to achieve such low emission levels would fail the cost-benefit determination needed to justify a beyond-the-floor option.

On the contrary, two environmental advocacy groups submitted comments opposing EPA's rationale for exempting Gas 1 units from CO limits on the basis of cost. The commenters argued that the only economic defense of work practice standards that would be justified was if economic limitations rendered the measurement of emissions "impracticable." Further, the commenters suggested that many of these Gas 1 units would require more than a tune-up to achieve comparable reductions to those estimated if a

numeric MACT floor standard was required.

Another commenter representing the coal industry also disagreed with EPA's use of a public policy rationale to justify a work practice for Gas 1 units instead of demonstrating that a work practice meets the requirements under section 112(h). The commenter argued that cost considerations were not relevant in a MACT floor analysis and they noted that the per unit costs of complying with MACT standards for gas units are lower than the cost for coal units.

Many commenters from industry, industry trade groups, universities, and State agencies agreed that emission limits would provide a disincentive to operate or switch to natural gas and refinery gas fired units. Commenters claimed that if limits for Gas 1 were adopted, units would switch from natural gas to electric systems powered by coal. Commenters stated that EPA correctly concluded that imposing emission limitations on gas-fired boilers would create a disincentive for switching to gas from oil, coal, or biomass as a control technique and would create an incentive for facilities to switch away from gas to other fuels.

A commenter from a private coal company indicated that EPA's concerns that establishing a MACT floor limit for Gas 1 units would incentivize fuel switching to coal or other fuels contradict EPA's rejection of fuel switching as a MACT floor alternative. The commenter added that if EPA rejected fuel switching because of its costliness and lack of a net emissions benefit, EPA should want to discourage coal units from converting to natural gas rather than promoting fuel switching to natural gas. This commenter also claimed that establishing a work practice standard for only Gas 1 units discriminated in favor of the use of natural gas and against the use of coal. The commenter argued that such a policy rationale invokes considerations that are not relevant in setting MACT floor standards and suggested that such a rationale is in violation of both CAA and the Equal Protection Clause of the Constitution. This commenter added that the only relevant statutory factor under 112(h) to help EPA determine where to apply a work practice standard was whether the hazardous air pollutant cannot be emitted through a conveyance designed and constructed to emit or capture that pollutant, whether the use of such a conveyance would be inconsistent with law, or whether the application of measurement methodology is not practicable due to technological and economic limitations.

Response: EPA has determined that it is not feasible to prescribe numerical emissions standards for Gas 1 units because the application of measurement methodology is not practicable due to technological and economic limitations. Therefore, EPA is finalizing the work practice standards for Gas 1 units. The commenters correctly point out that the measured emissions from these units are routinely below the detection limits of EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units. Even CO, which commenters correctly point out was tested at many natural gas and refinery gas-fired units, was below the level EPA considers to be a reliable measurement for more than 80 percent of the test runs that were conducted on Gas 1 units. The case for other pollutants is even more compelling as the majority of measurements are so low as to cast doubt on the true levels of emissions that were measured during the tests. Of the 48 test runs for HCl, 98 percent were below three times the maximum reported measurement detection level; similarly, 100 percent of the Hg runs, and 45 percent of the PM data were below three times the maximum reported measurement detection level. It is unusual to see numbers near the detection limit for PM since the "detection" involves a comparatively simple (compared to other test methods) weighing procedure, and the overall result indicates that the emissions are very close to zero. All of the dioxin tests had multiple non-detect isomers. Overall, the available test methods are greatly challenged, to the point of providing results that are questionable for all of the pollutants, when testing natural gas units. Because of these technological limitations that render it impracticable to measure emissions from Gas 1 units, EPA is also unable to establish the actual performance of the best performers as well as sources outside of the top performing 12 percent. The inability to accurately measure emissions from Gas 1 units and the related economic impracticability associated with measuring levels that are so low that even carefully conducted tests do not accurately measure emissions warrant setting a work practice standard under CAA section 112(h). EPA is establishing a requirement to implement a tune-up program as described in Section III.D of this preamble. As noted by many commenters, the tune-up program is an effective HAP emissions limitation technology. The requirement of an annual tune-up will allow these units to continue to combust the cleanest fuels

available for boilers while minimizing emissions to the same degree that is consistent with the operating practices of the best performing units in the subcategory.

2. Combining Gas 1 and Gas 2 Subcategories

Comment: Several commenters requested consolidation of the Gas 1 and Gas 2 subcategories into a single gas-fired subcategory. The majority of commenters supported this concept by suggesting that there is very little difference between emissions from the top performing sources in each of the two gas subcategories. One commenter specifically argued that in most cases the mean emission levels for Gas 2 fuels are within range and confidence intervals for individual Gas 1 fuels and that the differences in fuel characteristics do not have a first order impact on HAP emissions. The commenter reported on communications with a facility in the database firing a heavy recycle liquid and natural gas fuel combination, which indicated that this unit is a liquid fuel boiler and they provided an analysis of the dataset without this heavy recycle data where the confidence intervals for the remaining landfill gas, biogas/natural gas, and coke oven gas all overlap that for Gas 1 fuels. The commenter also claimed that if 12 outliers from two process gas facilities are eliminated, the remaining 232 of 244 CO data points within Gas 2 fuel group compare favorably with, even lower than, CO levels from Gas 1 fuels. Another commenter stated that pilot scale and field data studies have concluded that emissions of organic HAP from gaseous fuels are not significantly affected by fuel type.

In lieu of a single gas subcategory, several of the commenters requested that the Gas 1 subcategory be expanded to include gases similar to natural gas and refinery gas. These commenters argued, much like the commenters advocating for a single gas-fired subcategory, that units fired with process gases generated in chemical plants, pulp and paper plants, iron and steel plants, and similar operations should be included in the Gas 1 subcategory because the emissions data show very little difference in performance. One commenter stated that most of the Gas 2 fuels, including all 9 of the data points used in the proposed floor calculations, are from chemical plants. The commenter added that at a minimum, chemical plant process gas should be grouped with refinery gas in Gas 1 and a new floor made for Gas 2. One commenter noted

that EPA did not gather information on composition or heating value in the Phase 1 ICR survey to justify placing chemical process gases in a separate subcategory from natural gas and refinery gas. Another commenter submitted combustion properties of refinery gas and petrochemical gas in order to argue that they are very similar in composition and should be categorized with natural gas in the Gas 1 category.

In order to accomplish this expansion of the Gas 1 subcategory, many commenters also addressed the definition of natural gas and refinery gas. One commenter simply stated that all gases derived from hydrocarbon sources should be classified under the Gas 1 subcategory. Another commenter suggested the definition of refinery gas in 40 CFR part 63 subpart CC for the Petroleum Refineries NESHAP should be used in this final rule. The commenter went on to say that such gases from petrochemical processes have similar compositions to those stated in the Subpart CC definition (e.g. methane, hydrogen, light hydrocarbons, and other components) that are used as fuel in boilers and process heaters and thus should be subcategorized as Gas 1. One commenter stated that the definition of natural gas should be consistent across federal air regulations and suggested that the definition of natural gas should be edited to be consistent with the definition provided in 40 CFR Part 60 Subpart Db. Another commenter requested that the definition of Gas 1 include any boiler or process heater burning at least 90 percent natural gas, refinery gas, or process off-gases with metals and sulfur content equal or less than those in natural gas.

Many other commenters argued that in general the definition of natural gas needs to be broadened to account for non-geological origins of natural gas such as landfill gas, biogas, and synthetic gas in order to promote the use of these renewable fuels. This commenter went on to state that the Gas 1 subcategory excludes biogas and process off gases that have no metals and very comparable combustion characteristics to that of natural gas or refinery gas. One commenter argued that landfill gas (LFG) should be included in Gas 1 with the work practice approach because placing it in the Gas 2 subcategory conflicts with EPA Landfill Methane Outreach Program goals. The commenter goes on to say that there is no assurance that all limits can be achieved with control technologies and installation of controls will be prohibitively expensive and thus LFG projects will be stopped or replaced

with natural gas. A few commenters suggested that EPA did not have enough data on combustion of anaerobic digester gas to differentiate it from natural gas. One commenter requested confirmation that biogas under the proposed rule would be subject to Gas 2 emission limits. Another commenter requested that EPA separate and clearly define gaseous fuels derived from biomass and noted that depending on the source these fuels can contain chlorine or Hg and constituents that lead to the formation of dioxins and furans. With respect to syngas, one commenter suggested that EPA adopt a definition similar to that used in the 40 CFR part 60 subpart YYY standards for stationary combustion turbines. The commenter noted that if the purity of syngas was a concern, a solution would be to require the syngas to meet minimum specifications in part 261 of the hazardous waste regulations. Another commenter requested that Integrated Gas Combined Cycle units that use a gasifier to convert coal to gas and remove impurities before combustion be classified under the Gas 1 subcategory.

Three commenters specifically argued for the inclusion of propane fired boilers within the Gas 1 subcategory. One commenter stated that if propane meets the specifications of ASTM D1835-03a or other specification types like the Gas Processors Association Standard 2140-92 it should be included within the Gas 1 definition. Another commenter requested clarification that boilers firing liquefied petroleum gas (LPG) or propane-derived synthetic natural gas (SNG) as a backup fuel are still classified as Gas 1 boilers. The commenter argued that propane or LPG is mixed with air to make SNG and should be considered natural gas for the purposes of this final rule.

Several commenters specifically requested that hydrogen plant tail gas or similar process gases that are derived from natural gas be included in the Gas 1 subcategory. Commenters argued that hydrogen fuels do not contain HAP and subcategorizing the fuel as Gas 2 subjects the units to limits that would achieve no further reduction of HAP but require extensive performance testing, recordkeeping, fuel analysis and monitoring requirements. One commenter submitted historical facility data from a unit firing byproduct hydrogen and the commenter claimed that the fuel is cleaner burning than natural gas. One commenter suggested an 8 percent by volume minimum hydrogen content in hydrogen-fueled process gases as a criterion for consideration as a Gas 1 fuel. The

commenter mentioned that this percentage is based on a 1998 EPA document that established a minimum hydrogen content by volume for non-assisted flare combustion efficiency.

If a separate Gas 2 subcategory remains in the rule, many other commenters requested that work practices be extended to the Gas 2 subcategory based on the claim that gas-fired units, relative to units firing other fuels, have the lowest emissions and pose the lowest risk of all the subcategories. Thus, the use of gas should be encouraged rather than discouraged. Some commenters argued that as a consequence of establishing limits for Gas 2 fuels, some plant sites currently designed to use Gas 2 streams for energy efficient operations will be forced to dispose of process off-gases in other types of combustion sources such as flares. The commenters added that such disposal would result in essentially the same emissions from combustion of the Gas 2 stream using a flare (as opposed to combusting the fuel in a boiler) and additional emissions from consumption of natural gas that would be used in lieu of the Gas 2 fuel. Overall, the standard as proposed for Gas 2 units would result in increased emissions of all pollutants and lower fuel efficiency.

Response: EPA has determined that to the extent that process gases are comparable to natural gas and refinery gas, combustion of those gases in boilers and process heaters should be subject to the same standards as combustion of natural gas and refinery gas. Boilers that combust other gaseous fuels that have comparable emissions levels to Gas 1 units are similar in class and type to Gas 1 units because they share common design, operation, and emissions characteristics. Therefore, we are providing a mechanism by which units that combust gaseous fuels other than natural gas and refinery gas can demonstrate that they are similar to Gas 1 units and will therefore be subject to the standards for Gas 1 units. EPA originally examined the possibility of basing such a demonstration on levels of mercury and chlorine content in the gases, but no information was available regarding the chlorine content of natural gas or refinery gas, and no proven test methods were identified to quantify chlorine content of natural gas. Therefore, EPA is requiring a demonstration that other gases have levels of H₂S and Hg that are no higher than those found in Gas 1 units. Natural gas purity is commonly defined considering the sulfur content of the gas, in the form of H₂S. Sweet natural gas, which is considered pipeline

quality gas, contains no more than 4 ppmv H₂S. Information on Hg levels typical of natural gas was available through literature, and domestic natural gas Hg concentrations range up to about 40 micrograms per cubic meter. Using H₂S and Hg concentration as parameters for establishing equivalent contamination levels to natural gas, EPA is providing a fuel specification that can be used by facilities to qualify Gas 2 units for the Gas 1 standards. The fuel specification would also allow facilities to perform pre-combustion gas cleanup in order to qualify Gas 2 units for the Gas 1 standards. Boilers using process gases that do not meet the fuel specification and are not processed to meet the contaminant levels must meet the emissions limits for Gas 2 units.

3. Dioxin/Furan Emission Limits or Work Practices

Comment: Many commenters disagreed with the proposed dioxin/furan emission limits. Some commenters noted that a large majority of the dioxin/furan test data are non-detect values. As such, under section 112(h)(2)(b) of the CAA, the commenters noted that EPA has the authority to establish work practice standards when “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.” Other commenters stated that dioxin/furan formation in industrial boilers is not well understood and it would not be possible to duplicate the emissions from the facilities tested during the Phase II ICR that were used as the basis of the limit. One commenter indicated they will undergo preliminary research on the dioxin/furan removal efficiency of ESP and scrubbers, but much additional research is needed. Several commenters also added that there are no demonstrated technologies that would allow the units to reduce their emissions below the limit. Furthermore, control device vendors commented that they would not be able to guarantee their equipment will be able to control dioxin/furan for the affected boilers and process heaters due to lack of practical experience on boilers and process heaters. They also noted that most industry experience in controlling dioxin/furan is for waste-to-energy plants where concentrations of these pollutants are much higher than the reported Phase II ICR testing results.

Many commenters believe EPA is not authorized to regulate the entire dioxin/furan class as is currently proposed. They noted that in the section 112 HAP list only two compounds are specifically named, dibenzofuran and 1,3,7,8 TCDD,

and the MACT floor must be limited to those two and not all 17 congeners. Furthermore, some commenters stated that neither the initial EPA source category list (EPA-450/3-91-030) or the 2004 Boiler MACT rule identified dioxin/furan as a pollutant to be regulated.

Some commenters stated that regulating dioxin/furan emissions from these boilers and process heaters is not necessary because they are not a significant source of emissions. They noted that dioxin/furan emissions are significantly higher in units that burn chlorinated wastes and only those applicable rules (e.g. CISWI and Municipal Waste Combustors) should focus on regulating dioxin/furan. Having a limit in this Boiler MACT would only cause undue burden with minimal environmental impact. Given the uncertainties surrounding dioxin/furan emissions, a few commenters suggested EPA should do a thorough review prior to finalizing limits for this final rule to determine how this source category affects public health. It is suggested that EPA review the following questions: What portions of the annual total dioxin/furan emissions are contributed by this source category; what are the other major sources of dioxin/furan throughout the country; what are the current conditions for dioxin/furan exposure throughout the U.S.; have levels been going down or changing and if so by how much; and, could reductions be achieved more effectively by examining other sources of dioxin/furan?

In lieu of a specific dioxin/furan limit, many commenters suggested that CO should be used as a surrogate and meeting the CO limit would reduce dioxin/furan. While EPA stated in the preamble to the proposed rule that it is not appropriate to use CO as a surrogate, these commenters stated that the precursors to dioxin/furan formation are produced by incomplete combustion and thus dioxin/furan formation itself is indirectly related to the combustion process similar to the other organic HAP CO is currently used as a surrogate for. Another commenter suggested that control of other HAP such as Hg will provide adequate incidental control and reduction of dioxin/furan and the cost of separately monitoring dioxin/furan is not warranted taking into consideration the cost of achieving such emission reductions, energy requirements, and environmental impacts as required by Section 112(d)(2) of the CAA.

On the contrary, another commenter suggested that EPA correctly recognized that dioxin/furan can be formed outside of the combustion unit, not as part of

the combustion process, and so sets separate standards for these carcinogens.

Several commenters provided specific comments on a lack of data available for boilers burning bagasse in a combined suspension and grate firing design.

As an alternative to the limits, many commenters offered suggestions for a work practice standard to minimize dioxin/furan emissions. These comments focused on creating boiler-specific plans for implementing good combustion practices along with an operations and maintenance plan. Additionally, boiler operators could maintain a minimum temperature at the outlet of PM control devices to minimize dioxin/furan formation.

Response: In response to the comments that EPA is not authorized to regulate the dioxin/furan class as proposed, the commenters are incorrect. While dibenzofuran and 2,3,7,8 TCDD are two of the HAP listed in section 112, all dioxin and furan compounds are considered to be POM and, as such, EPA has the authority to regulate these compounds under section 112. The risk-related questions suggested by commenters are not applicable to establishment of the MACT floor standards under section 112(d), which are to be based on the average emissions performance of the best performing units for which the Administrator has emissions information. EPA received a number of comments on dioxin and furan emission limits regarding the ability of the test method to measure the typically low levels of emissions that are emitted from boilers and process heaters.

Commenters stated that the emissions were so low that they could not be measured, and therefore work practice standards, rather than emission limits, should be finalized for dioxin/furan for all subcategories. EPA disagrees. While emissions were below detectable levels in many tests for a large portion of the dioxin/furan isomers, virtually every test detected some level of dioxin/furan. Furthermore, some of the emission tests detected most or all isomers at some level. Dioxin/furan emissions can be precisely measured for at least some units in each subcategory except for Gas 1. Therefore, except for the Gas 1 subcategory, which is addressed elsewhere in this preamble, the statutory test for establishment of work practice standards—i.e., that measurement of emissions is impracticable due to technological and economic limitations—is not met.

In order to make sure that the emission limits are set at a level that can be measured, EPA used the “three times

MDL” approach (discussed elsewhere in this preamble) as a minimum level at which a dioxin/furan emission limit is set. Rather than finalizing work practice standards, but recognizing that emissions tend to be very low compared to more significant sources of dioxin such as incinerators, EPA’s approach to dioxin requires an initial compliance test to demonstrate that the units meet the dioxin/furan standard, and no additional compliance testing. Following a test demonstrating compliance with the emission limit, provided that the unit’s design is not modified in a manner inconsistent with good combustion practices, the oxygen level must be monitored, and the 12-hour block average must be maintained at or above 90 percent of the level established during the initial compliance test in order to provide an assurance of good combustion. Another important point to mention is that the dioxin/furan test method, EPA Method 23, requires that for compliance purposes, non-detect values should be counted as zero. Therefore, for purposes of compliance, the concern about not being able to meet the standards because of the contribution of non-detect values is moot.

4. Work Practices for Small Units

Comment: Many commenters stated EPA should treat new small units in the same manner as existing small units; for boilers and process heaters with a design capacity less than 10 MMBtu/hr, a work practice standard should be implemented instead of numerical limits. These commenters stated that the same technical and economic conditions under section 112(h) for existing units still held true for new units. New small boilers and process heaters (less than 10 mmBtu/hr) are typically designed like comparable existing units with small diameter stacks, or wall vents and no stack. These vents and small stacks do not allow for accurate application of standard EPA test methods required to demonstrate compliance with emission limits, and larger stacks would decrease the efficiencies of the units. They continued that while there are some savings in adding the controls and monitoring equipment during original construction, those savings were minor in comparison to the cost of the control and monitoring equipment itself. One commenter noted that the annual performance tests are over three times the cost of the boiler. In addition, other commenters stated that the D.C. Circuit has upheld EPA’s discretion to have insignificant emission sources exempt from regulations, and small units meet this condition.

Several of the commenters who supported work practice standards for small units also believed the size threshold should change. A few commenters suggested the size should be lowered to 5 MMBtu/hr, while most contended that the size threshold should be raised to 20, 25, or 30 MMBtu/hr. Those commenters who wanted the threshold raised noted that even boilers as large as 30 MMBtu/hr experience the same economic implications on their facilities. Some commenters also noted that 40 CFR part 60 subpart Dc New Source Performance Standards have work practice standards for units less than 30 MMBtu/hr. One State agency commented that the proposed rule established stringent emission limits for new small units. The commenter argued that a tiered approach should be used which required higher emission limits for new small units.

Conversely, some commenters agreed with EPA's proposed method of making the limits applicable to new small units. They noted that new boilers can be built with stacks appropriate for testing, or can have temporary stack extensions built for testing. One commenter added that it is not uncommon for new small boilers to vent exhaust into existing larger stacks that would allow for testing.

Response: We agree that the design of new and existing small units precludes the use of the suite of test methods required by this final rule. As pointed out by commenters, new small boilers and process heaters (less than 10 mmBtu/hr) are typically designed like comparable existing units with small diameter stacks, or wall vents and no stack. These vents and small stacks do not allow for accurate measurement of emissions using the standard EPA test methods required to demonstrate compliance with emission limits, and larger stacks would decrease the efficiencies of the units. Changes in stack diameters or addition of stacks in lieu of wall vents can impact efficiencies of boilers and can require significant redesign of boiler systems, which imposes significant economic limitations. Therefore, EPA has concluded that work practice standards are appropriate for new and existing small units because the measurement of emissions is impracticable due to technological and economic limitations.

E. New Data/Technical Corrections to Old Data

Comment: Many commenters identified shortcomings in EPA's emissions database, and multiple corrections were submitted to EPA both

through the public comment process and through e-mail communication with the ICR Combustion Survey team. Commenters also submitted new data directly to the ICR Combustion Survey Team and through the public comment process.

Response: EPA has incorporated all technical corrections and new data submitted since proposal. The corrections and new data are described in detail in a memorandum in the docket entitled "Handling and Processing of Corrections and New Data in the EPA ICR Databases."

F. Startup, Shutdown, and Malfunction Requirements

Comment: Numerous commenters raised concerns that insufficient data are currently available to establish emission standards for SSM events. Due to inherent limitations with measurement methods/technologies, which often require steady state conditions, emissions testing data and CEMS provide limited insight into SSM events, therefore combustor variability during these periods has been underestimated.

To address these data limitations, several commenters suggested that EPA should collect additional data that represent SSM events within each subcategory. One commenter had specific ideas for data collection including collecting SSM data from CEMS installed at the facilities previously included in the ICR survey and using portable analyzers to evaluate SSM emissions during future compliance testing. Many other commenters suggested that it would be infeasible to collect additional data given the test method limitations and suggested that a compliance work practice alternative be provided during periods of SSM. Commenters suggested that work practices should be site-specific, not be overly prescriptive, with the goal of minimizing the emissions during SSM periods. Other commenters suggested that EPA adopt an alternative to regulating emissions during SSM events and cited 40 CFR part 63 subpart ZZZZ, which states that startup time must be minimized.

Several commenters expressed separate concerns for EPA's treatment of malfunction events. Many commenters suggested that malfunction events should be excluded from emission limits and many submitted alternatives to including these periods. One commenter supported a limited allowance for malfunction periods where EPA defines the term "malfunction" and precisely identifies events requiring an immediate and complete shutdown. Another

commenter suggested EPA should require facilities to develop and implement work practice standards to reduce malfunctions and minimize pollutants emitted during these periods. A third commenter asked that EPA replicate California permits which include a specific provision for malfunction.

Many industry commenters recognized that the proposal preamble included a statement indicating that EPA promised to address periods of equipment malfunction by considering other information before enforcing exceedance of operating limits. However, the commenters suggested that this promise does not prevent EPA, a State, or a plaintiff in a citizen suit from determining that an exceedance during a malfunction constitutes a violation. These commenters preferred EPA to develop explicit compliance alternatives for malfunctions in the rule language.

Several commenters contended that EPA failed to recognize the inherent limitations in the technology and operating conditions used to reduce emissions during SSM. One commenter referenced a case (*Portland Cement Ass'n v. Ruckelshaus* (D.C. Cir. 1973)) where the court acknowledged that "startup" and "upset" conditions due to plant or emission device malfunction are an inescapable aspect of industrial life and that allowance must be accounted for in the standards. Aside from meeting emission limits, commenters provided examples of other operating parameters that are affected during SSM including: Elevated oxygen levels, air pollution control device operating parameters such as sorbent injection rates or ESP voltage, and fuel feed rates, among others. Commenters also raised concerns that applying limits during startups will require sources to decide between safety and environmental compliance by encouraging sources to try to shorten the startup period. For example, some commenters noted that decreasing the warm-up period could cause metallurgical and refractory stresses on the boiler. One commenter indicated that EPA's proposed rule had unnecessarily disregarded the special circumstance, an affirmative defense, of excess emissions allowed in a September 20, 1999, EPA policy memo about State Implementation Plans (SIP). The commenter added that affirmative defense provisions have recently been approved into several states SIP (e.g., Colorado [71 FR at 8959] and New Mexico [74 FR at 46912]). Both the Colorado SIP and the New Mexico SIP contain an affirmative defense for excess

emissions during periods of startup and shutdown.

Response: EPA has considered these comments and has revised this final rule to incorporate a work practice standard for periods of startup and shutdown. Information provided on the amount of time required for startup and shutdown of boilers and process heaters indicates that the application of measurement methodology for these sources using the required procedures, which would require more than 12 continuous hours in startup or shutdown mode to satisfy all of the sample volume requirements in the rule, is impracticable. Upon review of this information, EPA determined that it is not feasible to require stack testing—in particular, to complete the multiple required test runs—during periods of startup and shutdown due to physical limitations and the short duration of startup and shutdown periods. Operating in startup and shutdown mode for sufficient time to conduct the required test runs could result in higher emissions than would otherwise occur. Based on these specific facts for the boilers and process heater source category, EPA has developed a separate standard for these periods, and we are finalizing work practice standards to meet this requirement. The work practice standard requires sources to minimize periods of startup and shutdown following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, sources must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.

Regarding comments on treatment of malfunctions, the discussion of EPA's position on malfunctions in the section of this preamble entitled "What are the requirements during periods of startup, shutdown, and malfunction" provides details related to this response. Essentially, EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times. In 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).

Finally, EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (See, e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). EPA is, therefore, adding to this final rule an affirmative defense, as requested by public comment, to civil penalties for exceedances of numerical emission limits that are caused by malfunctions.

G. Health Based Compliance Alternatives

Comment: In the proposed rule, EPA considered whether it was appropriate to exercise its discretionary authority to establish health-based emission limits (HBEL) under section 112(d)(4) for HCl and other acid gases and proposed not to adopt such limits, citing, among other things, information gaps regarding facility-specific emissions of acid gases, co-located sources of acid gases and their cumulative impacts, potential environmental impacts of acid gases, and the significant co-benefits expected from the adoption of the conventional MACT standard. Comments were received both supporting this position and refuting it. Several commenters suggested legal, regulatory and scientific reasons for why HBEL or health-based compliance alternatives (HBCA) for HCl and Mn might be appropriate for this MACT standard. With respect to legal concerns, industry commenters indicated that section 112(d)(4) of the CAA establishes a mechanism for EPA to exclude facilities from certain pollution control regulations and circumstances when these facilities can demonstrate that emissions do not pose a health risk. Commenters cited a Senate Report that influenced development of 112(d)(4), where Congress recognized that, "For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment." [Footnote: S. Rep. No. 101-128 (1990) at 171]. Commenters also cited regulatory precedence for addressing HCl as a threshold pollutant, including the

Hazardous Waste Combustors and the Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semicemical Pulp Mills NESHAP. Commenters requested that EPA incorporate the flexibility afforded by 112(d)(4) and allow sources reasonable means for demonstrating that their respective emissions do not warrant further control. Industry commenters also cited the 2004 vacated Boiler MACT as precedence for HBCA for both HCl and Mn. The commenters contended that EPA failed to explain why the health based emissions limitations it established in the 2004 Boiler MACT and the justification provided for those limitations should now be reversed. The commenters also cited a 2006 court briefing where EPA vigorously defended the HBCA included in the 2004 rule when it was challenged in the D.C. Circuit [Final Brief For Respondent United States Environmental Protection Agency, D.C. Cir. Case No. 04-1385 (Dec. 4, 2006) at 59-65, 69.].

Citizen groups also commented that on August 6, 2010, EPA adopted a NESHAP for Portland Cement plants. In its final rule EPA specifically rejected adoption of risk-based exemptions for HCl and Mn. The commenter argues there are no differences sufficient to warrant a reversal of that decision in the Boiler MACT standard. Citizen groups also raised concerns that health risk information cited by EPA for HCl, hydrogen fluoride, hydrogen cyanide, and Mn does not establish "an ample margin of safety" and, therefore, no health threshold should be established. The commenters believe risk-based exemptions at levels less stringent than the MACT floor are prone to lawsuits that could potentially further delay implementation of the Boiler MACT.

Co-Located Source Issues

Many commenters responded to EPA comment solicitation on how it should "appropriately" simulate all reasonable facility/exposure situations. Commenters contended that boilers can be located among a wide variety of industrial facilities, which makes predicting and assessing all possible mixtures of HCl and other emitted air pollutants difficult. These simulations would require the consideration of emissions from nearby facilities for the almost 15,500 boilers affected by this final rule. Commenters also characterized defining of exposure situations as challenging, for example PM can serve as "carriers" to bring the adhered HAP deep within the lung, where the HAP can interact with the respiratory system directly or be leached

off of the particle surface and become available systemically. These commenters argue that the questions posed by the Agency in the preamble to the proposed rule illustrate why the MACT standard setting is and should be the default requirement in the 1990 Clean Air Act, rather than “health-based” standard-setting under section 112(d)(4).

Some commenters disagreed with using a hazard quotient (HQ) approach to establish a risk-based standard because the HQ would not account for potential toxicological interactions. The commenter noted that an HQ approach incorrectly assumes the different acid gases affect health through the same health endpoint, rather than assuming that the gases interact in an additive fashion. This commenter suggested that a hazard index approach, as described in EPA’s “Guideline for the Health Risk Assessment of Chemical Mixtures” would be more appropriate.

Industry commenters dispute that emissions from other sources or source categories should be considered when developing an HBCA and they argued that Congress expected EPA to consider the effect of co-located facilities during the 112(f) residual risk program instead of under 112(d). Commenters added that there is no prior EPA precedent for considering co-located facilities from a different source category during the same 112 rulemaking. Commenters also provided examples where co-located sources and source categories are not a concern, such as small municipal utilities that do not operate co-located HAP sources within their fence line and are not located in heavily populated urban areas where other HAP sources are common due to zoning. Representatives of the small municipal utility industry suggested that concerns of co-located HAP sources should not be used to arbitrarily deny health-based relief already approved on a site-specific basis.

Co-Benefits of Controlling HCl and Mn

Several commenters disputed EPA’s consideration of non-HAP collateral emissions reductions in setting MACT standards. They contended that EPA’s sole support for its “collateral benefits” theory is legislative history—the Senate Report that accompanied Senate Bill 1630 in 1989 and noted that the D.C. Circuit rejected this use of this theory since the Senate Report referred to an earlier version of the statute that was ultimately not enacted. Instead commenters suggested that other components of the CAA, such as the National Ambient Air Quality Standards (NAAQS), are more appropriate avenues

for mitigating emissions of criteria pollutants. Some commenters in the biomass industry noted that even if co-benefits of non-HAP were considered relevant to the analysis, the nominal co-benefits of reducing SO₂ emissions from biomass units would be limited due to the low inlet sulfur levels of this fuel.

Several other commenters suggested it is impossible to assess an established health threshold for HCl such that a 112(d)(4) standard could be set without evaluating the collateral benefits of a MACT standard. And, as described in the recently finalized cement kiln MACT rule, setting technology-based standards for HCl will result in significant reductions in the emissions of other pollutants, including SO₂, Hg, and PM. The commenter added that these reductions will provide enormous health and environmental benefits, which would not be experienced if section 112(d)(4) standards had been finalized. These commenters contended that HCl and other dangerous acid gases produced by commercial and industrial boilers pose substantial risks to industrial workers, as well as surrounding communities, and must be limited by the strict conventional MACT standards.

Cost Impacts of HBCA

Several commenters indicated that the current economic climate requires EPA to balance economic and environmental interests and they indicated that HBCA would help target investments into solving true health threats where limits are no more stringent or less stringent than needed to protect public health. Many commenters provided compliance cost savings if an HBCA is included in this final rule. For example, representatives of one industry estimated aggregated capital savings in excess of \$100 million just for the small facilities in the pulp & paper sector. Some commenters stressed the importance of an HBCA options for small entities affected by the regulations. Several other commenters suggested that EPA should estimate the costs and environmental effects of the HBCA option compared to a conventional MACT standard in order to make an informed decision on the adoption of an HBCA.

Response: After considering the comments received, some of which supported adoption of an emissions standard under section 112(d)(4) and some of which opposed such a standard, EPA has decided not to adopt an emissions standard based on its authority under section 112(d)(4) in the final rule. EPA first notes that the Agency’s authority under section

112(d)(4) is discretionary. That provision states that EPA “may” consider established health thresholds when setting emissions standards under section 112(d). By the use of the term “may,” Congress clearly intended to allow EPA to decide not to consider a health threshold even for pollutants which have an established threshold. As explained in the preamble to the proposed rule, it is appropriate for EPA to consider relevant factors when deciding whether to exercise its discretion under section 112(d)(4). EPA has considered the public comments received and is not adopting an emissions standard under section 112(d)(4) for the reasons explained below.

First, as explained in the preamble to the proposed rule, EPA continues to believe that the potential cumulative public health and environmental effects of acid gas emissions from boilers and other acid gas sources located near boilers supports the Agency’s decision not to exercise its discretion under section 112(d)(4). EPA requested in the preamble to the proposed rule information regarding facility-specific emissions of acid gases from boilers as well as sources which may be co-located with boilers. In particular, information concerning the variation of acid gas emission rates that can be expected from the various subcategories of units was identified as a significant data gap. Additional data were not provided during the comment period, and the data already in hand regarding these emissions are not sufficient to support the development of emissions standards for any of the boilers subcategories under section 112(d) that take into account the health threshold for acid gases, particularly given that the Act requires EPA’s consideration of health thresholds under section 112(d)(4) to protect public health with an ample margin of safety. In addition, the concerns expressed by EPA in the proposal regarding the potential environmental impacts and the cumulative impacts of acid gases on public health were not assuaged by the comments received.

EPA also received comments recommending not only that EPA establish emissions standards for acid gases pursuant to section 112(d)(4), but that it do so by excluding specific facilities from complying with emissions limits if the facility demonstrates that its emissions do not pose a health risk. EPA does not believe that a plain reading of the statute supports the establishment of such an approach. While section 112(d)(4) authorizes EPA to consider the level of

the health threshold for pollutants which have an established threshold, that threshold may be considered “when establishing emissions standards under [section 112(d).]” Therefore, EPA must still establish emissions standards under section 112(d) even if it chooses to exercise its discretion to consider an established health threshold.

As explained in the preamble to the proposed rule, EPA also considered the co-benefits of setting a conventional MACT standard for HCl. EPA considered the comments received on this issue and continues to believe that the co-benefits are significant and provide an additional basis for the Administrator to conclude that it is not appropriate to exercise her discretion under section 112(d)(4). EPA disagrees with the commenters who stated that it is not appropriate to consider non-HAP benefits in deciding whether to invoke section 112(d)(4). Although MACT standards may directly regulate only HAPs and 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. See S. Rep. No. 101–228, 101st Cong. 1st sess. at 172. EPA consequently does not accept the argument that it cannot consider reductions of criteria pollutants, for example in determining whether to take or not take certain discretionary actions, such as whether to adopt a risk-based standard under section 112(d)(4). There appears to be no valid reason that, where EPA has discretion in what type of standard to adopt, EPA must ignore controls which further the health and environmental outcomes at which section 112(d) of the Act is fundamentally aimed because such controls not only reduce HAP emissions but emissions of other air pollutants as well.⁷ Thus, the issue being addressed is not whether to regulate non-HAP under section 112(d) or whether to consider other air quality benefits in setting section 112(d)(2) standards—neither of which EPA is doing—but rather whether to make the discretionary choice to regulate certain HAP based on the MACT approach and whether EPA must put blinders on and ignore collateral environmental benefits when choosing whether or not to exercise that discretion. EPA knows of no principle in law or common sense that precludes it from doing so.

Finally, EPA is not adopting an HBEL for manganese, as some commenters

recommended. EPA did not propose or solicit comment on the adoption of an HBEL for manganese emissions, and since the final rule regulates PM as a surrogate for HAP metals and therefore does not establish a specific emissions limit for manganese, there is no reason to consider whether it would be appropriate to exercise section 112(d)(4) authority for manganese.

H. Biased Data Collection From Phase II Information Collection Request Testing

Comment: Many commenters noted that in selecting units for the Phase II testing, EPA targeted only those units whose data EPA determined it would need to set the MACT floor. The commenters contended that the targeted units were generally better performing units so the proposed limits reflect performance of the best 12 percent of the best rather than performance of the best 12 percent of the entire population as Congress intended. Further, they added that this skewed dataset led to a set of proposed emission limits that are more stringent than would have resulted from a random sampling of all the regulated sources. Several commenters also provided input on how EPA should have designed its Phase II test plan in order to develop a representative dataset. They added that representativeness may be considered as the measure of the degree to which data accurately and precisely represent a characteristic of a population. The commenters identified EPA’s approach for selecting Phase II testing sites as a form of judgmental sampling, which EPA defines as the “selection of sampling units on the basis of expert knowledge or professional judgment.” These commenters then cited an EPA document (Data Quality Assessment: A Reviewer’s Guide, EPA QA/G–9R, p. 11, U.S. EPA 2006) which outlines preferred sampling procedures for emission data. According to this document, probabilistic sampling (random selection) is preferable where EPA wishes to draw quantitative conclusions about the sampled population through statistical inferences. When using judgmental sampling, however, this document stated that “statistical analysis cannot be used to draw conclusions about the target population,” and “quantitative statements about the level of confidence in an estimate (such as confidence intervals) cannot be made.” Yet the commenters point out that EPA did use the Phase II data to perform statistical analyses and establish a MACT floor emission limit for each subcategory. The commenters added that generally, conclusions drawn from judgmental

samples apply only to those individual samples while aggregation of data collected from judgmental samples may result in severe bias due to lack of representativeness and lead to highly erroneous conclusions. Many commenters also suggested methods to mitigate the bias in the Phase II testing. Some commenters suggested that instead of taking the top 12 percent of units with stack test data available, EPA should determine how many units comprise the top 12 percent of a given subcategory and then use data from that many units to compute the floor. The commenters suggested that this approach is warranted because the Phase I ICR data allowed EPA to reliably select the top performers in each subcategory for purposes of collecting the Phase II information. Other commenters suggested that EPA supplement its ICR survey and testing data with other data sources such as fuel records, production records and associated emission factors from AP–42, commercial warranties and guarantees, or other EPA databases such as the National Emission Inventory or Toxics Release Inventory. Other commenters requested that EPA incorporate data from the ICR Phase II testing as long as these data are from a unit that has similar fuel and control device characteristics to the units identified in the top 12 percent.

Response: Section 112 specifies that MACT floors must be based on sources for which emissions information is available to the Administrator. While EPA’s Phase II data collection did target units with particular control configurations, these units were identified to fill data gaps, including providing additional information on the effectiveness of the various control technologies that are used to control emissions from boilers and process heaters. EPA disagrees with commenters who recommended that EPA should use data from the number of units that comprise 12 percent of a subcategory to calculate the floor, even where the Agency lacks information for all sources in the subcategory. That approach would be inconsistent with the language of section 112(d)(3), which clearly states that, for existing sources, the MACT floor cannot 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).” This is precisely what EPA has done in today’s final rule. The commenters’ recommended approach would instead base the floors on the average emission limitation achieved by

⁷ EPA notes the support of commenter 2898 in this regard.

all the sources for which EPA has emissions information, rather than that achieved by the best-performing 12 percent, if emissions information is only available for 12 percent of sources. This outcome would contradict the language of the statutory MACT floor provision.

EPA also notes that sources had ample opportunity to perform testing on other units and submit the data to EPA for consideration. EPA informed various industry groups that additional test data would be welcomed, and to the extent that additional data were provided, such data were used in the floor-setting process. Furthermore, the large majority of the proposed emission limits were based on data from both phases of the ICR, with most of the data coming from the phase I ICR, in which EPA requested any existing emissions data, and commenters do not allege any bias associated with the phase I data. The only emission limits that were based primarily on phase II ICR data were the dioxin/furan limits, and for those pollutants, the units were not selected based on any assumptions about their dioxin/furan emissions or the effectiveness of add-on controls. Instead, the units were selected to ensure that data would be available to set floors for the subcategories that EPA was considering at the time of the Phase I ICR.

I. Issues Related to Carbon Monoxide Emission Limits

Comment: Numerous commenters disagreed with EPA's statement that CO emissions do not vary significantly over the operating range of a unit, 75 FR 32029. These commenters provided limited data across the operating range of boilers showing significant variation in CO emissions; the data also support the contention that CO emissions are higher at low load. In addition, commenters note that the degree of variability in emissions is dependent upon a specific unit and its design and operation characteristics, as well as other factors. With the premise that boilers do have variable CO emissions, in order to meet the applicable emission limit, commenters stated that stable boiler operation would be necessary, but that such boiler operation is not always possible. They contend that boiler loads vary constantly and rapidly and such load swings are a normal part of many processes and operations. Factors affecting the load include changes in fuel mix, fuel quantity, and fluctuations in load demand. Quick changes or large swings can also result in spikes which are substantially higher than average emissions. Commenters stated that in addition to daily fluctuations, CO

emissions vary depending on broader issues such as business cycles or the time of year. Commenters claimed that even the top performers could not meet the limits due to load fluctuations.

Some commenters provided input from boiler manufacturers and the guarantees that are currently available on the market for CO emissions. These guarantees include provisions that void the guarantee at loads below 25 percent load. Burner and boiler manufacturers state that CO emissions do fluctuate with load and suggest that limits should not be lower than manufacturer guarantees.

Many commenters took issue with the use of stack test data to set the emission limit. Due to the highly variable nature of CO emissions, setting a standard that boilers must meet at all times based on stack test data does not properly characterize boiler emissions. Noting that stack tests are typically conducted at 90 percent of full load, commenters contended that this represents a small and unrepresentative snapshot in time captured during the best operating conditions. Some commenters compared stack test averages to CEMS values showing extreme differences (CEMS data could be >10 times higher), and stated that stack tests do not come close to capturing the long-term variability of CO emissions. Furthermore, commenters stated that some boilers frequently operate at low-fire conditions and that stack tests are not conducted at "representative operation conditions". A few commenters cited the DC Circuit [*Sierra Club v. EPA*, 167 F.3d 658, 665 (D.C. Cir. 1999)] and pointed out that stack tests do not capture the level of performance a unit will achieve "under the most adverse circumstances which can reasonably be expected to recur." The commenters claimed that this condition must be considered in setting MACT floors.

While EPA did present a comparison of data from units that had both stack test and hourly CO CEMS data available, commenters stated that the data are not representative. EPA presented only three units which have CEMS data and stack test data, and these units do not have data over a wide load range that could be considered to represent typical operating conditions. Commenters also noted that no CEMS data for liquid units were available. Many commenters suggested that EPA acquire and incorporate more CEMS data when setting the limits to show a more accurate picture of variability. A few commenters also pointed out that CEMS data is needed to characterize intra-unit operating variability due to load

changes, because the 99 percent UPL only characterizes inter-unit, steady-state operation. Looking at the CEMS data provided, some commenters used the "start anew" method to calculate a 30-day rolling average, and claimed that the unit would exceed the CO limit for several days, showing that the proposed limits are too low and the CEMS data are not appropriately considered.

Some commenters noted the discrepancy between using stack test data to set the limits, and then having to comply by using CEMS. They suggested that whichever method is used to set the limits, the same method should be used for compliance. Several commenters pointed out that although the vacated Boiler MACT included a requirement for CO CEMS, it did not require CO CEMS data obtained at less than 50 percent of maximum load to be included in the 30-day CO average. Commenters recommended that these data exclusions be incorporated in the compliance provisions of this final rule. In addition, a few commenters cited a ruling by the U.S. Court of Appeals for the D.C. Circuit that "a significant difference between techniques used by the Agency in arriving at standards, and requirements presently prescribed for determining compliance with standards, raises serious questions about the validity of the standard." (*Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 396 (DC Cir. 1973)). These commenters stated that the primary difference between these two methods is that the variability experienced during normal operations will not be captured during the stack test but will become apparent as the facility operates a CEMS over time.

Finally, many commenters stated that the low proposed CO limits will cause additional challenges to boilers that are subject to NO_x limits. These commenters presented graphs and data to demonstrate the inverse relationship between CO and NO_x emissions and noted that changing the boiler operation to reduce CO to such low levels would result in an increase in NO_x emissions. Commenters added that this result would be particularly challenging, and perhaps unproductive for boilers located in ozone non-attainment areas. In addition to increasing NO_x emissions, commenters noted that driving emission levels down to extremely low CO levels would also require boiler operators to increase excess air, thereby reducing the efficiency of the boiler. This operational change would require additional fuel to be combusted, thus increasing emissions of other HAP. These commenters requested that CO limits be

balanced with NO_x limits such that boiler efficiency is optimized and State efforts to comply with NAAQS are not hindered. In addition to concerns surrounding competing air quality standards, a few commenters stated that National Fire Protection Act (NFPA) requirements also affect CO emissions at low loads. The NFPA specifies a minimum airflow at which a boiler can operate regardless of load, in order to avoid boiler explosions. At low loads, this NFPA requirement can result in excess air which leads to increased CO emissions. Commenters added that in order to meet the limits as proposed, boilers may have to idle at a higher load, increasing fuel costs and other emissions (NO_x, carbon dioxide (CO₂), and HAP).

Response: In response to the many comments regarding the proposed CO emission limits, EPA performed a re-assessment of the available data. In addition, EPA analyzed additional data that were not used to develop the proposed limits, including data submitted prior to proposal but too late for consideration for purposes of the proposed rule, data submitted during the public comment period, and data submitted after the comment period closed. While many comments were received opposing EPA's proposal to set limits based on stack test data, EPA cannot set limits based on CEMS data because the available CEMS data are insufficient to set emission limits that are reflective of the best performing 12 percent of sources in the various subcategories. First, CEMS data are not available for all of the subcategories. Second, most of the subcategories have only a single CEM data set from one facility. In contrast, a large amount of CO stack test data are available. For these reasons, EPA concluded that it was appropriate to use the stack test data rather than the CEMS data for setting the MACT floors for CO. Industry commenters who recommended that the emission limits be based on CEMS had ample opportunity to conduct CEMS testing (on the units identified as "best performers" based on the 3-run stack tests or on additional units to provide a broader base of data), but very little CEMS data were submitted to EPA after the proposal, and significant data gaps still exist. EPA does agree that, based on the high degree of variability shown by the available data for CO from boilers and process heaters, CEM-based limits could accurately reflect the actual emissions. However, EPA would need sufficient CEMS data to accurately calculate emissions limits, and,

therefore, another approach must be used. In this instance, the alternative that EPA selected was to base the limits on 3-run stack test data.

To develop emission limits based on 3-run stack tests, EPA first reviewed the emission test reports for the best performing sources in order to ensure that that data reflected the actual performance of the units during the testing periods. EPA also incorporated data corrections from facilities that submitted test data, and between these two quality assurance measures, EPA has ensured that accurate data were used to establish the emission limits. Second, EPA examined the operating load at which the stack tests were conducted and found that, as pointed out by multiple commenters, the stack test data are representative of conditions at or near full load. Third, EPA determined that the calibration range of the CO analyzer must be considered in determining the minimum value that can be supported technically during a CO stack test. This assessment of calibration range resulted in some low CO levels being adjusted upward, as explained in more detail in the docket memo entitled "Assessment of Minimum Levels of CO that Can Be Established Under Various Analyzer Calibration Ranges." EPA then ranked the data for each subcategory and developed stack test-based emission limits using the 99.9 percent UPL. The 99.9 percent level was selected to provide an additional allowance for variability in the CO emission limits, since the CEM data show that CO levels have a higher degree of variability than other pollutants (for which EPA continues to use the 99 percent UPL). This change from the proposed 99 percent UPL level resulted in about a 10 percent increase in each of the CO emission limits (from the 99 percent UPL using the same data). The CO emission limits in today's rule must be met through the use of a stack test during the initial and annual compliance tests, and parametric monitoring is required to demonstrate continuous compliance. As discussed elsewhere in the preamble, during periods of startup and shutdown, units that would otherwise be subject to a numeric emission limit are instead subject to a work practice standard.

J. Cost Issues

1. Inaccuracy of Basis of Costs

Comment: Numerous commenters disagreed with EPA's cost estimates. Many of them provided specific cost estimates for bringing their facilities into compliance with the proposed

regulation to show that the costs were considerably higher than the EPA estimate. The estimations given included vendor data, real project costs, Best Achievable Control Technology and Best Available Retrofit Technology analyses and industrial control cost studies.

Several commenters stated that the Office of Air Quality Planning and Standards (OAQPS) cost manual used to estimate costs was outdated and inaccurate. They noted costs that were missing from the estimates, such as additional man-hours for record-keeping, compliance plan development and implementation, and operating and maintenance expenses. Some costs were said to be underestimated, such as the estimates for catalysts and carbon injection.

Response: The OAQPS cost manual is the accepted basis of cost estimates for EPA regulations. EPA welcomed new information or methods for estimating costs and used the available data to adjust cost estimates where appropriate. EPA did not adjust catalyst costs since this information provided by commenters was based on proprietary cost estimates that could not be scaled to all boiler types. This catalyst also represented a regenerative oxidative catalyst which was a different technology than the CO oxidation catalyst used in initial estimates from EPA at proposal. The main concern about carbon injection costs was that the technology would be needed on far more units than estimated, because the assumption that fabric filters would be adequate to achieve the Hg emission limits was incorrect. EPA has adjusted the emission limits since proposal and notes that none of the units in the MACT floor calculations for solid fuels use activated carbon injection (ACI) control. Of the solid fuel units in the MACT floor calculations that are achieving the floor, only 2 units reported to have fabric filter and ACI installed and 132 units have only a fabric filter installed. The assumption that most units will meet the Hg floor using a fabric filter is reasonable and supported by the data on record. One commenter also questioned the inclusion of a factor for installing ACI equipment to an existing unit, saying that this important factor had been left out of the original calculation. A review of the ACI algorithm confirmed that the factor for installing the unit had been included originally, and no change was necessary.

Comment: One of the most frequently mentioned concerns was the difficulty of retrofitting existing units with add-on control devices, which could lead to the

replacement of existing units, at a greater cost than what was estimated in the EPA background documents. Also mentioned were the increased costs associated with non-continental units, for which retrofits could be 1.3 to 2.3 times higher than elsewhere.

Response: EPA does not have enough information to assess the possibility of units being replaced due to difficulty retrofitting existing units. However, regardless of any information on that topic, the emission standards must reflect the floor level of control. Costs and emission impacts estimated for the boiler MACT standard are intended to represent national impacts.

Consequently, costs for a specific facility may be lower or higher than what was estimated but on a national basis, we believe that our estimates are reasonable. We would also note that the cost algorithms include a cost factor for retrofitting existing boilers.

Comment: One commenter also expressed concern that process heaters had costs estimated using algorithms based on boiler add-on control costs, giving grossly underestimated process heater control costs.

Response: The algorithms estimate costs based on exhaust gas flow rate volumes and pollutant inlet concentrations and not specific to boiler costs. Some of the algorithms were based on costs from the 2009 HMIWI rulemaking. EPA considers these estimates to be reasonable estimates for both boilers and process heaters and the commenters did not provide an alternative cost estimate specific to process heaters.

Comment: Several commenters stated that the number of affected sources was also underestimated, especially for gas or liquid-fired units, and one requested clarification with regards to the discrepancy between the number of units estimated in the vacated rule and the proposal.

Response: The current inventory gathered for this rulemaking included unit data from industry sources. The public was encouraged to send any updates or changes necessary to correct the source inventory. The current inventory overrides the inventory created previously for the 2004 rulemaking.

2. Unproven Controls

Comment: Many commenters stated that the suggested add-on controls have not been proven capable of simultaneously achieving the low emission limits proposed for the affected units. They expressed dismay at the high cost of adding numerous control devices without any reassurance

that the emission limits could be achieved, or that human health would be better protected as a result. Some commenters included quotes from control device vendors stating that they were unable to guarantee the equipment could achieve the removal efficiency necessary to meet the proposed emission limits.

Response: EPA has adjusted emission limits and compliance mechanisms to address these concerns. These adjustments include creation of a consolidated solid fuel subcategory for fuel-based HAP and CO monitoring provisions.

3. Economic Hardship

Comment: Numerous commenters worried that the proposed rule would lead to plant shut-downs, job loss, discouraged use of renewable energy and other negative economic impacts not considered in the rule. The commenters stated that the proposed regulation fails to find balance between job preservation, economic growth and environmental protection and suggested that EPA use their discretionary authority under the CAA to craft a more appropriate rule. A few industry representatives worried that the cumulative impact of multiple EPA regulations was putting U.S. industry at a cost disadvantage compared to international companies, and another asked if costs to comply with other MACT standards were also being taken into account in the RIA. Other commenters stated that the cost of controls necessary for their units to comply with the proposed rule exceeded the cost of the boiler itself, and in many cases exceeded the costs of plant profits in recent years.

Response: EPA appreciates these concerns and, since proposal, has considered opportunities to reduce the costs of compliance with this final rule while continuing to achieve the public health objectives and meet the requirements of the CAA. In a number of cases in this final rule, EPA has adjusted emission limits, compliance mechanisms and subcategories that will make compliance less difficult and costly. In addition, EPA has added a discussion about the interaction of this rule with other rules to section 7.2 of the RIA.

4. Technical Concerns

Comment: In some cases, technical shortcomings of the cost estimates were addressed. For instance, one commenter pointed out that neither chlorine or Hg can be cost effectively removed from liquid fuels down to the proposed emission levels, so the cost of fuels will

likely increase as suppliers blend different fuel sources to achieve fuel requirements.

Response: EPA does not have the information necessary to estimate the potential costs that could result from new fuel blends.

Comment: Several commenters had concerns about the use of packed bed scrubbers as a suggested control device. They pointed out that these scrubbers can only be used with relatively small units having an exhaust flow rate no greater than 75,000 standard cubic feet per minute (scfm).

Response: EPA cost estimates took the flow rate capabilities of packed bed scrubbers into account by estimating additional scrubbers for units with flow rates beyond 75,000 scfm.

Comment: Other commenters mentioned that some facilities, most often rural plants in the wood products sector, do not have and cannot obtain a wastewater discharge permit, so they cannot use wet scrubbers and would need to install more costly dry scrubbers to meet the HCl emission limits.

Response: EPA added estimated costs for a Dry Injection/Fabric Filter control alternative for units unable to install wet scrubbers to meet HCl limits.

Comment: Several commenters stated that the proposed CO emission limits would not be achievable at all operating conditions while also meeting NO_x limits, unless controls are added. Several pointed out that tune-ups and combustion modifications such as a linkageless boiler management system (LBMS) and replacement burners would offer inadequate control in most cases.

Response: EPA incorporated additional CO data variability data received during the comment period, adjusted subcategories, and revised compliance mechanisms to address the issues discussed in these comments.

Comment: One commenter pointed out that no documentation was found of a successful LBMS retrofit to existing biomass-to-energy facilities using stoker or fuel cell oven combustion. This commenter cited conversations with several stoker burner manufacturers, and the commenter could find no stoker units that have been retrofitted with an LBMS. They added that manufacturers stated that a successful retrofit to meet the proposed standards was doubtful based on the inherent leakage of air in these types of facilities.

Response: EPA adjusted subcategories and compliance mechanisms and analyzed new CO test data in order to make the CO limits more reasonable. EPA estimates the cost of an LBMS as a placeholder for other combustion

improvements that are expected to achieve the CO limits.

Comment: Some wrote to suggest that the number of units requiring activated carbon injection is grossly underestimated, because fabric filters alone would be frequently inadequate to meet the proposed Hg limits. Other commenters suggested that the use of activated carbon would lead to increased fabric filter use and additional costs for disposing of the resulting waste stream.

Response: EPA adjusted Hg emission limits and incorporated a new solid fuel subcategory to address this concern. Further, many of the units in the MACT floor calculations demonstrate that they have achieved the Hg limit without installing activated carbon injection.

Comment: The commenters suggested that far more facilities would need to add fabric filters, rather than the less expensive electrostatic precipitators that had been included in the cost estimates.

Response: EPA is now basing the costs primarily on fabric filter installation, although owners/operators will choose a technology, that can meet the limits, that is best-suited to their process.

Comment: Several times, commenters expressed concern about required add-on controls conflicting with current controls and each other. For instance, one commenter explained small amounts of sulfur trioxide (SO₃) are generated as part of the combustion process for sulfur-containing fuels. The commenter noted that a CO oxidation catalyst or Selective Catalytic Reduction NO_x reduction catalyst, will convert an additional percentage of the SO₂ to SO₃, which will inhibit Hg removal efficiency of activated carbon injection. SO₃ occupies the active sites on the carbon, taking away those sites from the Hg. Additionally, some of these commenters also pointed out that some of the suggested control combinations have not been used with the affected boilers, so their use is unproven and the retrofit costs unknown.

Response: EPA recognizes the potential interaction of different control devices and has adjusted the subcategories and incorporated additional emission data into the emission limit calculations. The revised limits and subcategories incorporated in this final rule mitigate these concerns. However, specifically addressing the commenters concerns would require an extensive study of emissions and controls, and the time or resources to conduct such a study are not available. EPA used the available data to set standards as required under section 112.

Comment: Some commenters questioned the assumption that facilities will not incur costs to comply with the dioxin/furan standards because they will test for dioxin/furan and be below detection levels. They said this logic does not make sense because EPA has not outlined in the proposed rule any procedures for handling non-detects when performing compliance testing and there are boilers in the EPA emissions database with dioxin/furan emissions that are non-detect but actually measured emissions higher than the proposed limit.

Response: EPA adjusted the dioxin/furan emission limits based on data corrections and corrected procedures for handling non-detect and detection level limited values, making the need for add-on controls to achieve compliance even less likely. For matters of compliance, it should be noted that EPA Method 23 indicates that for compliance demonstrations, a value of zero should be used in place of a value below the detection limit for each non-detect isomer. Adherence to this procedure will ensure that non-detect values do not cause units to violate the emission limits.

Comment: Other commenters disagreed with the EPA assumption that an ESP would be installed to meet the PM emissions limit unless a unit already had a fabric filter installed because sorbent injection will be required to control acid gas, Hg, and dioxin/furan. When sorbent injection is required, the commenters suggested that fabric filters will likely be chosen for units without existing ESPs in order to maximize the performance of the sorbents and minimize the amount of sorbent used.

Response: EPA considers the original approach to be reasonable, and even more realistic, given the adjustments made to the emission limits.

5. Tune-up Costs

Comment: Some commenters questioned the inclusion of a tune-up in the proposed rule and suggested that many sites already perform regular tune-ups. Some commenters also disagreed with annualizing the cost of the tune-up and energy audit over a five year period. The commenters contended that since a tune-up is a service, it must be paid in year 1 to the individual or company performing the work.

Response: EPA agrees that some sites already perform regular tune-ups, which means the requirement will not increase costs for those facilities. EPA considers it appropriate to annualize the cost of a tune-up because the initial tune-up

involves more costly steps that make subsequent tune-ups less costly.

6. Testing and Monitoring Costs

Comment: Numerous commenters stated that there will be a significant burden associated with performance testing and that EPA has underestimated these costs. EPA used an estimate of \$55,000 plus \$6,500 for labor per test, while the commenters provided both estimated and actual testing costs ranging from \$60,000 to \$90,000. A few commenters also noted when testing for HCl and Hg the testing costs should be doubled, because to meet the 'worst-case' condition stipulation the boilers will have to maximize emissions for two different operating parameters. Additionally, when testing HCl and Hg it is required that units also test for CO, PM, and dioxin/furan which increases costs and complexity of tests. As a result of this paired testing, the number of liquid units estimated to need controls for Hg and HCl and which, therefore, must conduct a performance test is also low. A few commenters contended that if a unit uses CO CEMS a reduction of \$3,000 instead of \$7,000 from the test estimate is more accurate. These commenters also noted that additional fuel sampling costs for sources firing gas or solids are necessary given the requirements for sources firing more than one type of fuel. Commenters suggested that additional costs for adding ports or scaffolding to stacks; additional space and runs to conduct the sophisticated tests; modifications to the permitting or compliance system; man-hours to enter data into the ERT; increased overtime; lost production, unit downtime, and additional engineering effort to adjust operations; and an increased cost to contract stack testers due to high demand should be factored into the estimated overall testing costs.

Response: EPA's revised cost estimates include two tests for Hg and HCl for each unit in the solid fuel subcategory, in order to account for potential worst case conditions that may be necessary to satisfy this final rule's requirements. In addition, EPA is maintaining the reduced testing option for units that demonstrate emissions a specified percentage below the limits for three years. We have clarified and modified this option to state that performance testing for a given pollutant may be performed every 3 years, instead of annually, if measured emissions during 2 consecutive annual performance tests are less than 75 percent of the applicable emission limit.

Comment: To reduce the testing burden commenters provided input to

modify the rule. The proposed rule requires annual stack testing with the opportunity to qualify for testing every 3 years after 3 consecutive successful compliance demonstrations showing emissions, but many commenters suggested that a one-time test or one test every 5 years, coupled with parameter monitoring, is more appropriate.

Response: In order to reduce the cost of the testing requirements, EPA adjusted a couple of requirements based on the public comments. First, at proposal, EPA specified that to qualify for testing once every 3 years, sources must meet a level at or below 75 percent of the emission limit for each pollutant for 3 consecutive years. We have modified this option so that performance testing for a given pollutant may be performed every 3 years, instead of annually, if measured emissions during 2 consecutive annual performance tests are less than 75 percent of the applicable emission limit. In addition, for dioxin/furan, we are changing the testing requirement to an initial test demonstrating compliance with the limit and no additional testing, provided that the unit's design is not modified in a manner inconsistent with good combustion practices. In addition, the oxygen level must be maintained at or above 90 percent of the level during the initial compliance test in order to provide an assurance of good combustion. The rationale behind the adjusted dioxin compliance demonstration is that the measured emissions from a limited number of tests indicate that dioxin emissions from boilers and process heaters are very low, and while it is required that sources meet the MACT floor levels, a one-time test and the required parameter monitoring are sufficient to ensure that combustion conditions are maintained and that the dioxin emissions remain low while also minimizing costs.

Comment: Similarly, many commenters contended that costs associated with CO and PM CEMS are underestimated as well. For the installations of CEMS, one commenter provided a cost estimate which was 3 times higher than the EPA estimate, while another said that costs for planning and engineering could be as much as 40 times higher with annual operating costs 3 times higher than EPA estimates. Also, in addition to the capital cost for the instrument itself, expensive certification costs are necessary; one commenter stated that this would be an additional \$30,000 to \$50,000 for each CEMS. Commenters noted that even for units where CEMS has already been installed, new equipment may be necessary in order to

comply with proposed requirements for certifying and calibrating the CEMS. Commenters stated that a data acquisition system would be necessary to manage the data, which can cost more than \$10,000. Many commenters also discussed the necessity of adding a stack platform, access, and additional utilities which can exceed \$100,000 per stack.

Response: EPA has removed CO CEMS requirements from this final rule. The costs detailed in Appendix J-2 of the memorandum "Methodology for Estimating Control Costs for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source (2010)" include planning, installations, RATA certifications, performance specifications and QA/QC checks. For PM CEMS, EPA's estimates of installed capital costs include planning, selecting equipment, support facilities, installation, performance specifications tests and QA/QC and is consistent with estimates provided in the 2009 HMIWI rulemaking. EPA does not have information on which facilities would need to install a stack platform or utilities. Given that PM CEMS are required on only the largest units, EPA considers its assumption that most larger facilities have platform and utility access reasonable.

K. Non-hazardous Secondary Materials

Comment: Commenters from several environmental non-governmental organizations were concerned that if EPA moves forward with the proposal to define non-hazardous solid waste to exclude a majority of secondary materials burned for energy recovery, EPA will effectively exempt many boilers from any regulation. These commenters suggested that boilers burning secondary materials are not included in the regulatory definition of solid waste will not be regulated under § 129 because EPA will have labeled the secondary materials burned as a non-waste. Further, they suggested that these non-waste secondary materials are not covered under the boiler rules under § 112. These commenters suggested that while some boilers burning secondary materials will be included in EPA's categories for coal, oil, or biomass fired units, a large group of units will remain unregulated, including units burning only solid secondary materials or only secondary materials and gaseous fuels. One commenter stated that EPA must set section 112 standards for these units to meet its obligations under section 112 and the order in *Sierra Club v. EPA*, No 01-1537 (D.D.C.) requiring EPA to

"promulgate emission standards assuring that sources accounting for not less than 90 percent of the aggregate emissions of each of the hazardous air pollutants enumerated in Section 112(c)(6) are subject to emission standards under section 112(d)(2) or (d)(4) no later than December 16, 2010." These commenters were concerned that exempting units that burn secondary material from any emission standards will have adverse impacts on the communities that are exposed to the uncontrolled pollutants.

Response: EPA has amended the definitions in this final rule to cover boilers burning non-hazardous secondary materials.

VI. Impacts of This Final Rule

A. What are the air impacts?

Table 2 of this preamble illustrates, for each basic fuel subcategory, the emissions reductions achieved by this final 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, Hg, metals, and volatile organic compounds) will be reduced by 40,000 tons per year for existing units and 60 tons per year for new units. Emissions of HCl will be reduced by 30,000 tons per year for existing units and 29 tons per year for new units. Emissions of Hg will be reduced by 1.4 tons per year for existing units and 10.8 pounds per year for new units. Emissions of filterable PM will be reduced by 47,400 tons per year for existing units and 85 tons per year for new units. Emissions of non-Hg metals (*i.e.*, antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, Mn, nickel, and selenium) will be reduced by 2,700 tons per year for existing units and will be reduced by 1.5 tons per year for new units. In addition, emissions of SO₂ are estimated to be reduced by 442,000 tons per year for existing sources and 400 tons per year for new sources. Emissions of dioxin/furan, will be reduced by 23 grams of TCDD-equivalents per year for existing units and 0.01 gram per year of TCDD-equivalents for new units. A discussion of the methodology used to estimate emissions and emissions reductions is presented in "Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source (2011)" in the docket.

TABLE 2—SUMMARY OF EMISSIONS REDUCTIONS FOR EXISTING AND NEW SOURCES
(Tons/Yr)

Source	Subcategory	HCl	PM	Non mercury metals ^a	Mercury	VOC
Existing Units	Solid units	27,592	33,299	314	0.6	5,046
	Liquid units	1,936	13,269	2,229	0.7	1,881
	Non-Continental Liquid units.	89	726	115	0.06	0.01
	Gas 1 (NG/RG) units	23	139	0.3	0.009	82
	Gas 1 Metallurgical Furnaces.	0.4	2	0.02	0.001	30
	Gas 2 (other) units	0.4	0.1	0.0009	4.5E-05	111
New Units	Solid units	0	0	0	0	0
	Liquid units	29	85	1.5	0.005	27
	Gas 1 units	0.02	0.1	0.0003	7.9E-06	0.03
	Gas 2 (other) units	0	0	0	0	0

^a Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, Mn, nickel, and selenium.

B. What are the water and solid waste impacts?

EPA estimated the additional water usage that would result from installing wet scrubbers to meet the emission limits for HCl would be 700 million gallons per year for existing sources and 242,000 gallons per year for new sources. In addition to the increased water usage, an additional 266 million gallons per year of wastewater would be produced for existing sources and 194,000 gallons per year for new sources. The annual costs of treating the additional wastewater are \$1.4 million for existing sources and \$1,055 for new sources. These costs are accounted for in the control costs estimates.

EPA estimated the additional solid waste that would result from the MACT floor level of control to be 100,450 tons per year for existing sources and 580 tons per year for new sources. Solid waste is generated from flyash and dust captured in PM and Hg controls as well as from spent carbon and spent sorbent that is injected into exhaust streams or used to filter gas streams. The costs of handling the additional solid waste generated are \$4.2 million for existing sources and \$25,000 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 “Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source (2011)”.

C. What are the energy impacts?

EPA expects an increase of approximately 1.442 billion kilowatt hours (kWh) in national annual energy usage as a result of this final rule. Of this amount, 1.436 billion kWh would

be from existing sources and 6.2 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 this final rule. Additionally, 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 53 TBtu each year from existing sources and an additional 11 billion BTU each year from new sources. 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 cost impacts?

To estimate the national cost impacts of this final 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. If a unit did not report emission data but similar units at the facility with the same fuel and combustor design reported data, the average of all similar units at a given facility was assigned as its baseline emissions. If no unit-specific or similar units from the same facility had data available, a baseline average emission factor was assigned to the unit. Units that reported non-detect emission data for a pollutant that did not have a standardized numeric detection limit were assigned to the average of all non-detect emission data for that pollutant. For the remaining 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 final MACT floor emission limit to determine if control devices were needed to meet the emission limits. The control analysis considered fabric filters and activated carbon injection to be the primary control devices for Hg control, ESP for units meeting Hg limits but requiring additional control to meet the PM limits, wet scrubbers, dry injection/fabric filters, or increased caustic rates to meet the HCl limits, depending on whether or not the facility was assumed to have a wastewater discharge permit, 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 Hg control in order to avoid overestimating the costs. We also included costs for testing and monitoring requirements contained in this final rule. The resulting total national cost impact of this final rule is 5.1 billion dollars in capital expenditures and 1.8 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 1.4 billion dollars. The total capital and annual costs include costs for control devices, work practices, testing and monitoring. Table 3 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 3—SUMMARY OF CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES

Source	Subcategory	Estimated/pro- jected number of affected units	Capital costs (10 ⁶ \$)	Testing and monitoring annualized costs (10 ⁶ \$/yr)	Annualized cost (10 ⁶ \$/yr) (con- sidering fuel savings)
Existing Units	Solid units	1,014	2,183	108	846
	Liquid units	713	2,656	19.8	828
	Non-Continental Liquid units	27	86	0.7	21
	Gas 1 units	10,797	70	0.3	(325)
	Gas 1 Metallurgical Furnaces	694	4.5	0	(6)
	Gas 2 (other) units	118	79	6.3	37
	Limited Use	477	3.1	0	(25)
Energy Assessment	ALL				27
New Units	Solid units	0	0	0	0
	Liquid units	13	21	0.3	6.1
	Gas (NG/RG) units	34	0.2	0	(0.02)
	Gas (other) units	0	0	0	0

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 this final rule in the 3rd year is 21 million dollars in capital expenditures and 6.1 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 and reduced testing allowance in this final 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 “Revised Methodology for Estimating the Control Costs for Industrial, Commercial, and Institutional Boiler and Process Heater NESHP (2011)” and “Revised Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Industrial Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source (2011)” in the Docket.

E. What are the economic impacts?

Under this final rule, EPA’s economic model suggests the average national market-level variables (prices, production-levels, consumption, international trade) will not change significantly (e.g., are less than 0.01 percent). 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 above 3 percent for 8 of the 50 small entities included in the screening analysis.

In addition to estimating this rule’s social costs and benefits, EPA has estimated the employment impacts of the final rule. We expect that the rule’s direct impact on employment will be small. We have not quantified the rule’s indirect or induced impacts. For further explanation and discussion of our analysis, see Chapter 4 of the RIA.

F. What are the benefits of this final rule?

The benefit categories associated with the emission reduction anticipated for this rule can be broadly categorized as

those benefits attributable to reduced exposure to hazardous air pollutants (HAPs) and those attributable to exposure to other pollutants. Because we were unable to monetize the benefits associated with reducing HAPs, all monetized benefits reflect improvements in ambient PM_{2.5} and ozone concentrations. This results in an underestimate of the total monetized benefits. We estimated the total monetized benefits of this final regulatory action to be \$22 billion to \$54 billion (2008\$, 3 percent discount rate) in the implementation year (2014). The monetized benefits at a 7 percent discount rate are \$20 billion to \$49 billion (2008\$). Using alternate relationships between fine particulate matter (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.⁸ A summary of the monetized benefits estimates at discount rates of 3 percent and 7 percent is provided in Table 4 of this preamble. A summary of the avoided health incidences is provided in Table 5 of this preamble.

TABLE 4—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT

[Millions of 2008\$]¹

Pollutant	Emissions re- ductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
PM_{2.5}-related benefits			
Direct PM _{2.5}	29,007	\$2,100 to \$5,100	\$1,900 to \$4,600.
SO ₂	439,901	\$20,000 to \$49,000	\$18,000 to \$45,000.
Ozone-related benefits			
VOCs	6,537	\$3.6 to \$15	\$3.6 to \$15.

⁸Roman *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 4—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT—Continued
[Millions of 2008\$]¹

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
Total	\$22,000 to \$54,000	\$20,000 to \$49,000.

¹ All estimates are for the implementation year (2014), and are rounded to two significant figures so numbers may not sum across rows. All fine particles are assumed to have equivalent health effects. Benefits from reducing hazardous air pollutants (HAP) are not included. These estimates do not include energy disbenefits valued at \$22 million. These benefits reflect existing boilers and 47 new boilers anticipated to come on-line by 2014.

TABLE 5—SUMMARY OF THE AVOIDED HEALTH INCIDENCES FOR THE FINAL BOILER MACT¹

	Avoided health incidences
Avoided Premature Mortality	2,500 to 6,500.
Avoided Morbidity	
Chronic Bronchitis	1,600.
Acute Myocardial Infarction	4,000.
Hospital Admissions, Respiratory	610.
Hospital Admissions, Cardiovascular	1,300.
Emergency Room Visits, Respiratory	2,400.
Acute Bronchitis	3,700.
Work Loss Days	310,000.
Asthma Exacerbation	41,000.
Minor Restricted Activity Days	1,900,000.
Lower Respiratory Symptoms	44,000.
Upper Respiratory Symptoms	34,000.
School Loss Days	810.

¹ All estimates are for the implementation year (2014), and are rounded to two significant figures. All fine particles are assumed to have equivalent health effects. Benefits from reducing HAP are not included. These benefits reflect existing boilers and 47 new boilers anticipated to come online by 2014.

These quantified benefits estimates represent the human health benefits associated with reducing exposure to PM_{2.5} and ozone. The PM and ozone reductions are the result of emission limits on PM as well as emission limits on other pollutants, including HAP. To estimate the human health benefits, we used the environmental Benefits Mapping and Analysis Program (BenMAP) model to quantify the changes in PM_{2.5} and ozone-related health impacts and monetized benefits based on changes in air quality. This approach is consistent with the recently proposed Transport Rule RIA.⁹

For this final rule, we have expanded and updated the analysis since the proposal in several important ways. Using the Comprehensive Air Quality Model with extensions (CAMx) model, we are able to provide boiler sector-specific air quality impacts attributable to the emission reductions anticipated from this final rule. We believe that this modeling provides estimates that are more appropriate for characterizing the health impacts and monetized benefits from boilers than the generic benefit-

per-ton estimates used for the proposal analysis.

To generate the boiler sector-specific benefit-per-ton estimates, we used CAMx to convert emissions of direct PM_{2.5} and PM_{2.5} precursors into changes in ambient PM_{2.5} levels and BenMAP to estimate the changes in human health associated with that change in air quality. Finally, the monetized PM_{2.5} health benefits were divided by the emission reductions to create the boiler sector-specific benefit-per-ton estimates. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. Directly emitted PM_{2.5} and SO₂ are the dominant PM_{2.5} precursors affected by this final rule. 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, SO₂ has a lower benefit-per-ton estimate than direct PM_{2.5} because it does not directly transform into PM_{2.5}, and because sulfate particles formed from SO₂ emissions can transport many miles, including over areas with low

populations. Direct PM_{2.5} emissions convert directly into ambient PM_{2.5}, thus, to the extent that emissions occur in population areas, exposures to direct PM_{2.5} will tend to be higher, and monetized health benefits will be higher than for SO₂ emissions.

In addition, we estimated the ozone benefits for this final rule. Volatile organic compounds (VOC) are the primary ozone precursor affected by this final rule. We used CAMx to convert emissions of VOC into changes in ambient ozone levels and BenMAP to estimate the changes in human health associated with that change in air quality.

Furthermore, CAMx modeling allows us to model the reduced Hg deposition that would occur as a result of the estimated reductions of Hg emissions. Although we are unable to model Hg methylation and human consumption of Hg-contaminated fish, the Hg deposition maps provide an improved qualitative characterization of the Hg benefits associated with this final rulemaking.

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 on both empirical (epidemiological) studies and

⁹ U.S. Environmental Protection Agency, 2010. RIA for the Proposed Federal Transport Rule. Prepared by Office of Air and Radiation, June. Available on the Internet at http://www.epa.gov/ttn/ecas/regdata/RIAs/proposaltrria_final.pdf.

judgments elicited from scientific experts, to characterize the uncertainty in the relationship between PM_{2.5} concentrations and premature mortality. For this final rule, we cite two key empirical studies, one based on the American Cancer Society cohort study¹⁰ and the extended Six Cities cohort study.¹¹ In the RIA for this final rule, which is available in the docket, we also include benefits estimates derived from expert judgments and other assumptions.

EPA strives to use the best available science to support our benefits analyses. We recognize that interpretation of the science regarding air pollution and health is dynamic and evolving. After reviewing the scientific literature and recent scientific advice, we have determined that the no-threshold model is the most appropriate model for assessing the mortality benefits associated with reducing PM_{2.5} exposure. Consistent with this recent advice, we are replacing the previous threshold sensitivity analysis with a new “lowest measured level (LML)” assessment. While an LML assessment provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations.

Most of the estimated PM-related benefits in this final rule would accrue to populations exposed to higher levels of PM_{2.5}. Using the Pope, *et al.*, (2002) study, 79 percent of the population is exposed at or above the LML of 7.5 microgram per cubic meter (µg/m³). Using the Laden, *et al.*, (2006) study, 34 percent of the population is exposed above the LML of 10 µg/m³. It is important to emphasize that we have high confidence in PM_{2.5}-related effects down to the lowest LML of the major cohort studies. This fact is important, because as we estimate PM-related mortality among populations exposed to levels of PM_{2.5} that are successively lower, our confidence in the results diminishes. However, our analysis shows that the great majority of the impacts occur at higher exposures.

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 other pollutants have not been monetized in this analysis, including reducing 167,000 tons of CO, 30,000 tons of hydrochloric acid, 820 tons of HF, 23 grams of dioxins/furans, 2,900 pounds of Hg, and 22,700 tons of other metals each year. Specifically, we were unable to estimate the benefits associated with HAPs that would be reduced as a result of this rule due to data, resource, and methodology limitations. Challenges in quantifying the HAP benefits include a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses, and the challenges of tracking health progress for diseases with long latency periods. Although we do not have sufficient information or modeling available to provide monetized estimates for this rulemaking, we include a qualitative assessment of the health effects of these air pollutants in the RIA for this final rule, which is available in the docket. In addition, we provide maps of reduced mercury deposition anticipated from these rules in the RIA for this final rule.

In addition, the monetized benefits estimates provided in Table 4 do not reflect the disbenefits associated with increased electricity usage from operation of the control devices. We estimate that the increases in emissions of CO₂ would have disbenefits valued at \$22 million at a 3 percent discount rate (average). CO₂-related disbenefits were calculated using the social cost of carbon, which is discussed further in the RIA. However, these disbenefits do not change the rounded total monetized benefits. In the RIA, we also provide the monetized CO₂ disbenefits using discount rates of 5 percent (average), 2.5 percent (average), and 3 percent (95th percentile).

This analysis does not include the type of detailed uncertainty assessment found in the 2006 PM_{2.5} NAAQS RIA or 2008 Ozone NAAQS RIA. However, the benefits analyses in these RIA provide an indication of the sensitivity of our results to various assumptions, including the use of alternative concentration-response functions and the fraction of the population exposed to low PM_{2.5} levels.

For more information on the benefits analysis, please refer to the RIA for this final rule that is available in the docket.

G. What are the secondary air impacts?

For units adding controls to meet the proposed emission limits, we anticipate very minor secondary air impacts. The combustion of fuel needed to generate additional electricity would yield slight increases in emissions, including NO_x, CO, PM and SO₂ and an increase in CO₂ emissions. Since NO_x and SO₂ are covered by capped emissions trading programs, and methodological limitations prevent us from quantifying the change in CO and PM, we do not estimate an increase in secondary air impacts for this final rule from additional electricity demand. We do estimate greenhouse gas impacts, which result from increased electricity consumption, to be 954,000 tons per year from existing units and 4,100 tons per year from new units.

VII. Relationship of This Final 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 emit two of the seven CAA Section 112(c)(6) pollutants: POM and Hg. (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 categories “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-

¹⁰ 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.

¹¹ Laden *et al.*, 2006. “Reduction in Fine Particulate Air Pollution and Mortality.” *American Journal of Respiratory and Critical Care Medicine*. 173: 667–672.

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 Hg emissions, as is evidenced by performance data. Specifically, the emission tests obtained at currently operating units show that the proposed MACT regulations will reduce Hg emissions by about 77 percent. It is, therefore, reasonable to conclude that POM emissions will be substantially controlled. Thus, while this final 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, CO serves as

an effective surrogate for this HAP, because CO, like POM, is formed as a byproduct of combustion, and both would increase with an increase in the level of incomplete 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 require numerical emissions limits for POM with respect to boilers and process heaters to satisfy CAA Section 112(c)(6).

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

VIII. Statutory and Executive Order Reviews

A. Executive Orders 12866 and 13563: Regulatory Planning and Review

Under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76

FR 3821, January 21, 2011), 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 Executive Orders 12866 and 13563 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 see the following table.

SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE BOILER MACT IN 2014
[Millions of 2008\$]

	3% Discount rate	7% Discount rate
Selected		
Total Monetized Benefits ²	\$22,000 to \$54,000	\$20,000 to \$49,000
Total Social Costs ³	\$1,500	\$1,500
Net Benefits	\$20,500 to \$52,500	\$18,500 to \$47,500
Non-Monetized Benefits	112,000 tons of CO. 30,000 tons of HCl. 820 tons of HF. 2,800 pounds of Hg. 2,700 tons of other metals. 23 grams of dioxins/furans (TEQ). Health effects from SO ₂ exposure. Ecosystem effects. Visibility impairment.	
Alternative		
Total Monetized Benefits ²	\$18,000 to \$43,000	\$16,000 to \$39,000
Total Social Costs ³	\$1,900	\$1,900
Net Benefits	\$16,100 to \$41,100	\$14,100 to \$37,100
Non-Monetized Benefits	112,000 tons of CO. 22,000 tons of HCl. 620 tons of HF. 2,400 pounds of Hg. 2,600 tons of other metals. 23 grams of dioxins/furans (TEQ). Health effects from SO ₂ exposure. Ecosystem effects. Visibility impairment.	

¹ All estimates are for the implementation year (2014), and are rounded to two significant figures. These results include units anticipated to come online and the lowest cost disposal assumption.

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 SO₂, as well as reducing exposure to ozone through reductions of VOCs. It is important to note that the monetized benefits include many but not all health effects associated with PM_{2.5} exposure. Benefits are shown as a range from Pope *et al.* (2002) to Laden *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. These estimates include energy disbenefits valued at \$23 million for the selected option and \$35 million for the alternative option. Ozone benefits are valued at \$3.6 to \$15 million for both options.

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.

B. Paperwork Reduction Act

The information collection requirements in this final rule will be submitted for approval to the OMB under the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* An ICR document has been prepared by EPA (ICR No. 2028.06). The information collection requirements are not enforceable until OMB approves them.

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.

This final rule would require maintenance inspections of the control devices but would not require any notifications or reports beyond those required by the General Provisions aside from the notification of alternative fuel use for those units that are in the Gas 1 subcategory but burn liquid fuels for periodic testing, or during periods of gas curtailment or gas supply emergencies. The recordkeeping requirements require only the specific information needed to determine compliance.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of this Subpart DDDDD. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonable preventable and not caused by poor maintenance and or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, EPA provides an administrative adjustment to this ICR that shows what the notification, recordkeeping and reporting requirements associated with the assertion of the affirmative defense might entail. EPA's estimate for the required notification, reports and records, including the root cause analysis, totals \$3,141 and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to EPA. EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense.

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 \$95.9 million. This includes 280,459 labor hours per year at a total labor cost of \$26.5 million per year, and total non-labor capital costs of \$69.3 million per year. This estimate includes initial and annual performance test, conducting an documenting an energy assessment, conducting fuel specifications for Gas 1 units, repeat testing under worst-case conditions for solid fuel units, 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 97,563 hours per year at a total labor cost of \$5.2 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 use technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the

existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act, as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996, 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 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 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.

Pursuant to section 603 of the RFA, EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review Panel to

obtain advice and recommendations of representatives of the regulated small entities. A detailed discussion of the Panel's advice and recommendations is found in the final Panel Report (Docket ID No. EPA-HQ-OAR-2002-0058-0797). A summary of the Panel's recommendations is also presented in the preamble to the proposed rule at 75 FR 32044-32045 (June 4, 2010). In the proposed rule, EPA included provisions consistent with four of the Panel's recommendations.

As required by section 604 of the RFA, we also prepared a final regulatory flexibility analysis (FRFA) for today's final rule. The FRFA addresses the issues raised by public comments on the IRFA, which was part of the proposal of this rule. The FRFA, which is included as a section in the RIA, is available for review in the docket and is summarized below.

Section II.A of this preamble describes the reasons that EPA is finalizing this action. The rule is intended to reduce emissions of HAP as required under section 112 of the CAA. Many significant issues were raised during the public comment period, and EPA's responses to those comments are presented in section V of this preamble or in the response to comments document contained in the docket. Significant changes to the rule that resulted from the public comments are described in section IV of this preamble.

The primary comments on the IRFA were provided by SBA, with the remainder of the comments generally supporting SBA's comments. Those comments included the following: EPA should have adopted a health-based compliance alternative (HBCA) which provides alternative emission limits for threshold chemicals; EPA should have adopted additional subcategories, including the following: Subcategories based on fuel type (including coal rank, bagasse, biomass by type, and oil by type), unit design type (e.g., process

heater, fluidized bed, stoker, fuel cell, suspension burner), duty cycle, geographic location, boiler size, burner type (with and without low-NO_x burners), and hours of use (limited use); EPA should have minimized facility monitoring and reporting requirements; EPA should not have proposed the energy audit requirement; EPA's proposed emissions standards are too stringent; and, EPA should provide more flexibility for emissions averaging.

In response to the comments on the IRFA and other public comments, EPA made the following changes to the final rule. EPA adopted additional subcategories, including a limited-use subcategory for units that operate less than 10 percent of the operating hours in a year, a non-continental liquid unit subcategory for units with the unique challenges faced by remote island locations, and a combination suspension/grate boiler subcategory. EPA also consolidated the subcategories for units combusting various types of solid fuels, which will simplify compliance and will allow units to combust varying percentages of different solid fuels without triggering subcategory changes. EPA also decreased monitoring and testing costs by eliminating the CO CEMS requirement for units greater than 100 mmBtu/hr and changing the dioxin testing requirement to a one-time test. The final rule also includes work practice standards for additional subcategories, including limited-use units, new small units, and units combusting gaseous fuels that are demonstrated to have similar contaminant levels to natural gas. Finally, EPA is finalizing emission limits that are less stringent than the proposed limits for most of the subcategory/pollutant combinations. The emission limit changes are largely due to the changes in subcategories, data corrections, and incorporation of new data into the floor calculations.

Additional details on the changes discussed in this paragraph are included in sections IV and V of this preamble.

While EPA did make significant changes based on public comment, EPA did not finalize a HBCA or HBELs and is maintaining, but clarifying, the energy assessment requirement. The discussion of the HBCA decision is included in section V of this preamble. Some changes to the energy assessment requirement that will reduce costs for small entities include the following provisions: The energy assessment for facilities with affected boilers and process heaters using less than 0.3 trillion Btu per year heat input will be one day in length maximum. The boiler system and energy use system accounting for at least 50 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing a one-day energy assessment; and the energy assessment for facilities with affected boilers and process heaters using 0.3 to 1.0 trillion Btu per year will be 3 days in length maximum. The boiler system and any energy use system accounting for at least 33 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing a 3-day energy assessment. In addition, energy assessments that have been conducted after January 1, 2008 are considered adequate as long as they meet or are amended to meet the requirements of the energy assessment.

While EPA did not make major adjustments to the emissions averaging provisions, the change to a solid fuel subcategory will enable all solid fuel-fired units at a facility to use the emissions averaging provision for Hg, PM, and HCl.

The rule applies to a many different types of small entities. The table below describes the small entities identified in the Combustion Facility Survey.

CLASSES OF SMALL ENTITIES

NAICS	NAICS description	Total number of facilities	Total number of small entities
111	Crop Production	1	0
113	Forestry and Logging	1	0
115	Support Activities for Agriculture and Forestry	1	0
211	Oil and Gas Extraction	24	3
212	Mining (Except Oil and Gas)	14	1
221	Utilities	183	23
311	Food Manufacturing	110	7
312	Beverage and Tobacco Product Manufacturing	5	0
313	Textile Mills	14	1
314	Textile Product Mills	1	0
316	Leather and Allied Product Manufacturing	3	1
321	Wood Product Manufacturing	183	18
322	Paper Manufacturing	186	14

CLASSES OF SMALL ENTITIES—Continued

NAICS	NAICS description	Total number of facilities	Total number of small entities
323	Printing and Related Support Activities	33	5
324	Petroleum and Coal Products Manufacturing	84	8
325	Chemical Manufacturing	220	17
326	Plastics and Rubber Products Manufacturing	89	11
327	Nonmetallic Mineral Product Manufacturing	41	2
331	Primary Metal Manufacturing	57	6
332	Fabricated Metal Product Manufacturing	46	8
333	Machinery Manufacturing	13	0
334	Computer and Electronic Product Manufacturing	2	0
335	Electrical Equipment, Appliance, and Component Manufacturing	12	0
336	Transportation Equipment Manufacturing	100	7
337	Furniture and Related Product Manufacturing	45	8
339	Miscellaneous Manufacturing	15	1
423	Durable Goods Merchant Wholesalers	1	1
424	Nondurable Goods Merchant Wholesalers	1	0
441	Motor Vehicle and Parts Dealers	1	0
481	Air Transportation	7	0
482	Rail Transportation	1	0
486	Pipeline Transportation	60	0
488	Support Activities for Transportation	3	0
493	Warehousing and Storage	5	1
531	Real Estate	1	0
541	Professional, Scientific, and Technical Services	8	0
561	Administrative and Support Services	1	0
562	Waste Management and Remediation Services	7	2
611	Educational Services	29	2
622	Hospitals	4	0
623	Nursing and Residential Care Facilities	1	0
811	Repair and Maintenance	1	0
921	Executive, Legislative, and Other General Government Support	2	0
928	National Security and International Affairs	23	0

We compared the estimated costs to the sales for these entities. The results are found in the following table.

SALES TESTS USING SMALL COMPANIES IDENTIFIED IN THE COMBUSTION SURVEY

Sample statistic	Proposal	Selected option	Alternative option
Mean	4.9%	4.0%	3.8%
Median	0.4%	0.2%	0.4%
Maximum	72.9%	59.8%	31.4%
Minimum	<0.01%	<0.01%	<0.01%
Ultimate parent company observations	50	50	50
Ultimate parent companies with sale tests exceeding 3%	14	8	13

For more detail please see the RIA.

The information collection activities in this ICR include initial and annual stack tests, fuel analyses, operating parameter monitoring, continuous O₂ monitoring for all units greater than 10 mmBtu/hr, continuous emission monitoring for PM at units greater than 250 mmBtu/hr, certified energy audits, annual or biennial tune-ups (depending on the size of the combustion equipment), preparation of a site-specific monitoring plan and a site-specific fuel monitoring plan, one-time and periodic reports, and the maintenance of records. Based on the distribution of major source facilities

with affected boilers or process heaters reported in the 2008 survey entitled "Information Collection Effort for Facilities with Combustion Units (ICR No. 2286.01)," there are 1,639 existing facilities with affected boilers or process heaters. Of these, 94 percent are located in the private sector and the remaining 6 percent are located in the public sector. A table included in the FRFA summarizes the types and number of each type of small entities expected to be affected by the major source rule.

The Agency expects that persons with knowledge of .pdf software, spreadsheet and relational database programs will be

necessary in order to prepare the report or record. Based on experience with previous emission stack testing, we expect most facilities to contract out preparation of the reports associated with emission stack testing, including creation of the Electronic Reporting Tool submittal which will minimize the need for in depth knowledge of databases or spreadsheet software at the source. We also expect affected sources will need to work with web-based applicability tools and flowcharts to determine the requirements applicable to them, knowledge of the heat input capacity and fuel use of the combustion

units at each facility will be necessary in order to develop the reports and determine initial applicability to the rule. Affected facilities will also need skills associated with vendor selection in order to identify service providers that can help them complete their compliance requirements, as necessary.

As required by section 212 of SBREFA, EPA also is preparing a Small Entity Compliance Guide to help small entities comply with this rule. Small entities will be able to obtain a copy of the Small Entity Compliance guide at the following Web site: <http://www.epa.gov/ttn/atw/boiler/boilerpg.html>. The guide should be available by May 20, 2011.

D. 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 final 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 final 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 ICI 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 this final 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 this final 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 this final rule and the predicted change in prices and production in the affected industries, the estimated social costs of this final rule are \$1.5 billion (2008 dollars).

It is estimated that 3 years after implementation of this final rule, HAP would be reduced by thousands of tons, including reductions in hydrochloric acid, hydrogen fluoride, metallic HAP including Hg, 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 SO₂ that would occur, including 28 thousand tons of PM_{2.5} and 443 thousand tons of SO₂. 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 SO₂) 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 SO₂ emissions reductions. For SO₂ 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 2014 associated with the implementation of the proposed alternative is range from \$22 billion (2008 dollars) to \$54 billion (2008 dollars) when using a 3 percent discount rate (or from \$20 billion (2008 dollars) to \$49 billion (2008 dollars) when using a 7 percent discount rate). This estimate, at a 3 percent discount rate, is about \$20.5 billion (2008 dollars) to \$52.5 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 rulemaking, refer to the RIA in the docket.

3. Future and Disproportionate Costs

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

We do not believe that there will be any disproportionate budgetary effects of this final 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 this final rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of this final 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 this 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 this final 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. We have consulted with State and local air pollution control officials. We have also held meetings on this final rule with many of the stakeholders from numerous individual companies, institutions, 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 this final rule contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may

have some sources affected by this final rule, the impacts are not expected to be significant. Therefore, this final rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

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

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this final 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.

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

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. Executive Order 13175 requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications."

EPA has concluded that this action may have tribal implications. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. This rule would impose requirements on owners and

operators of major industrial boilers. We are only aware of a few installations of industrial, commercial, or institutional boilers owned or operated by Indian tribal governments. We conducted outreach to tribal environmental staff on this rule through the Tribal Air Newsletter, discussions at the National Tribal Forum and the monthly conference call with the National Tribal Air Association, we also hosted a webinar on the proposed rule in which tribal environmental staff participated.

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

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be "economically significant" as defined under Executive Orders 12866 and 13563, 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 final 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 final rule is based solely on technology performance.

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

Executive Order 13211, (66 FR 28355, May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) that is a significant regulatory action under Executive Orders 12866, 13563, or any successor order, and (ii) is likely to have

a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action." This final 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 0.05 percent price increase for the energy sector and a -0.02 percent percentage change in production. We estimate a 0.09 percent increase in energy imports. For more information on the estimated energy effects, please refer to the economic impact analysis for this final rule. The analysis is available in the public docket.

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

I. National Technology Transfer and Advancement Act

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

This rulemaking involves technical standards. EPA cites the following standards in the final rule: EPA Methods 1, 2, 2F, 2G, 3A, 3B, 4, 5, 5D, 17, 19, 23, 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 final rule.

The voluntary consensus standard American Society of Mechanical

Engineers (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, CO₂, and CO 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 CO and oxygen concentrations for this final 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 Hg only) for the purpose of this final rule. This standard can be used in the final rule to determine the Hg concentration in stack gases for boilers with rated heat input capacities of greater than 250 MMBtu/hr.

In addition to the voluntary consensus standards EPA used in the proposed rule, the search for emissions measurement procedures identified 15 other voluntary consensus standards. 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 this final 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. 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 require 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 this final 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 milligram (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 Hg 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.

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 final 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. EPA estimates that there are approximately 13,840 units located at 1,639 facilities covered by this final rule.

This final rule will reduce emissions of all the listed HAP that come from boilers and process heaters. This includes metals (Hg, arsenic, beryllium, cadmium, chromium, lead, Mn, nickel, and selenium), organics (POM, acetaldehyde, acrolein, benzene, dioxin/furan, ethylene dichloride, formaldehyde, and polychlorinated biphenyls), 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. This final rule will also result in substantial reductions of criteria pollutants such as CO, NO_x, PM, and SO₂. SO₂ and nitrogen dioxide 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.)

Based on the fact that this final rule does not allow emission increases, EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low-income, or Tribal populations. To address Executive Order 12898, EPA has conducted analyses to determine the aggregate demographic makeup of the communities near affected sources. EPA's demographic analysis of populations within the three-mile radius showed that major source boilers are located in areas where minorities are overrepresented when compared to the national average. For these same areas, there is also an overrepresentation of population below the poverty line as compared to the national average. 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. 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 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 policies. To promote meaningful involvement, EPA has developed a communication and outreach strategy to ensure that interested communities have access to this final rule and are aware of its content. EPA also ensured that interested communities had an opportunity to comment during the comment period. During the comment period that followed the June 2010 proposal, EPA publicized the rulemaking via EJ newsletters, Tribal newsletters, EJ listservs, and the internet, including the Office of Policy's (OP) Rulemaking Gateway Web site (<http://yosemite.epa.gov/oepi/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.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective May 20, 2011.

List of Subjects in 40 CFR part 63

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

Dated: February 21, 2011.

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 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. Section 63.14 is amended by:
- a. Revising paragraphs (b)(27), (b)(35), (b)(39) through (44), (b)(47) through (52), (b)(57), (b)(61), (b)(64), and (i)(1).
 - b. Removing and reserving paragraphs (b)(45), (b)(46), (b)(55), (b)(56), (b)(58) through (60), and (b)(62).
 - c. Adding paragraphs (b)(66) through (68).
 - d. Adding paragraphs (p) and (q).

§ 63.14 Incorporations by reference.

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(b) * * *
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(27) ASTM D6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from

Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for § 63.9307(c)(2).

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(35) ASTM D6784–02 (Reapproved 2008) Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008, IBR approved for table 1 to subpart DDDDD of this part, table 2 to subpart DDDDD of this part, table 5 to subpart DDDDD of this part, and table 4 to subpart JJJJJ of this part.

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(39) ASTM D388–05 Standard Classification of Coals by Rank, approved September 15, 2005, IBR approved for § 63.7575 and § 63.11237.

(40) ASTM D396–10 Standard Specification for Fuel Oils, approved October 1, 2010, IBR approved for § 63.7575.

(41) ASTM D1835–05 Standard Specification for Liquefied Petroleum (LP) Gases, approved April 1, 2005, IBR approved for § 63.7575 and § 63.11237.

(42) ASTM D2013/D2013M–09 Standard Practice for Preparing Coal Samples for Analysis, approved November 1, 2009, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(43) ASTM D2234/D2234M–10 Standard Practice for Collection of a Gross Sample of Coal, approved January 1, 2010, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(44) ASTM D3173–03 (Reapproved 2008) Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, approved February 1, 2008, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

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(47) ASTM D5198–09 Standard Practice for Nitric Acid Digestion of Solid Waste, approved February 1, 2009, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(48) ASTM D5865–10a Standard Test Method for Gross Calorific Value of Coal and Coke, approved May 1, 2010, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(49) ASTM D6323–98 (Reapproved 2003) Standard Guide for Laboratory Subsampling of Media Related to Waste Management Activities, approved

August 10, 2003, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(50) ASTM E711–87 (Reapproved 2004) Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter, approved August 28, 1987, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(51) ASTM E776–87 (Reapproved 2009) Standard Test Method for Forms of Chlorine in Refuse-Derived Fuel, approved July 1, 2009, IBR approved for table 6 to subpart DDDDD of this part.

(52) ASTM E871–82 (Reapproved 2006) Standard Test Method for Moisture Analysis of Particulate Wood Fuels, approved November 1, 2006, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

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(57) ASTM D6721–01 (Reapproved 2006) Standard Test Method for Determination of Chlorine in Coal by Oxidative Hydrolysis Microcoulometry, approved April 1, 2006, IBR approved for table 6 to subpart DDDDD of this part.

* * * * *

(61) ASTM D6722–01 (Reapproved 2006) Standard Test Method for Total Mercury in Coal and Coal Combustion Residues by the Direct Combustion Analysis, approved April 1, 2006, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

* * * * *

(64) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, approved October 1, 2005, IBR approved for table 4 to subpart ZZZZ of this part, table 5 to subpart DDDDD of this part, and table 4 to subpart JJJJJ of this part.

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(66) ASTM D4084–07 Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), approved June 1, 2007, IBR approved for table 6 to subpart DDDDD of this part.

(67) ASTM D5954–98 (Reapproved 2006), Standard Test Method for Mercury Sampling and Measurement in Natural Gas by Atomic Absorption Spectroscopy, approved December 1, 2006, IBR approved for table 6 to subpart DDDDD of this part.

(68) ASTM D6350–98 (Reapproved 2003) Standard Test Method for Mercury Sampling and Analysis in Natural Gas by Atomic Fluorescence Spectroscopy, approved May 10, 2003, IBR approved for table 6 to subpart DDDDD of this part.

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(i) * * *

(1) ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus],” IBR approved for §§ 63.309(k)(1)(iii), 63.865(b), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), 63.11551(a)(2)(i)(C), table 5 to subpart DDDDD of this part, table 1 to subpart ZZZZZ of this part, and table 4 to subpart JJJJJ of this part.

* * * * *

(p) The following material is available from the U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, (202) 272–0167, <http://www.epa.gov>.

(1) National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants—Background Information for Proposed Standards, Final Report, EPA–453/R–01–005, January 2001, IBR approved for § 63.7491(g).

(2) Office Of Air Quality Planning And Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, EPA–454/R–98–015, September 1997, IBR approved for § 63.7525(j)(2) and § 63.11224(f)(2).

(3) SW–846–3020A, Acid Digestion of Aqueous Samples And Extracts For Total Metals For Analysis By GFAA Spectroscopy, Revision 1, July 1992, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(4) SW–846–3050B, Acid Digestion of Sediments, Sludges, And Soils, Revision 2, December 1996, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(5) SW–846–7470A, Mercury In Liquid Waste (Manual Cold-Vapor Technique), Revision 1, September 1994, in EPA Publication No. SW–846,

Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(6) SW-846-7471B, Mercury In Solid Or Semisolid Waste (Manual Cold-Vapor Technique), Revision 2, February 2007, in EPA Publication No. SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(7) SW-846-9250, Chloride (Colorimetric, Automated Ferricyanide AAI), Revision 0, September 1986, in EPA Publication No. SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part.

(q) The following material is available for purchase from the International Standards Organization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, <http://www.iso.org/iso/home.htm>.

(1) ISO 6978-1:2003(E), Natural Gas—Determination of Mercury—Part 1: Sampling of Mercury by Chemisorption on Iodine, First edition, October 15, 2003, IBR approved for table 6 to subpart DDDDD of this part.

(2) ISO 6978-2:2003(E), Natural gas—Determination of Mercury—Part 2: Sampling of Mercury by Amalgamation on Gold/Platinum Alloy, First edition, October 15, 2003, IBR approved for table 6 to subpart DDDDD of this part.

■ 3. 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?
 63.7485 Am I subject to this subpart?
 63.7490 What is the affected source of this subpart?
 63.7491 Are any boilers or process heaters not subject to this subpart?
 63.7495 When do I have to comply with this subpart?

Emission Limitations and Work Practice Standards

- 63.7499 What are the subcategories of boilers and process heaters?
 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

63.7501 How can I assert an affirmative defense if I exceed an emission limitations during a malfunction?

General Compliance Requirements

63.7505 What are my general requirements for complying with this subpart?

Testing, Fuel Analyses, and Initial Compliance Requirements

- 63.7510 What are my initial compliance requirements and by what date must I conduct them?
 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?
 63.7520 What stack tests and procedures must I use?
 63.7521 What fuel analyses, fuel specification, and procedures must I use?
 63.7522 Can I use emissions averaging to comply with this subpart?
 63.7525 What are my monitoring, installation, operation, and maintenance requirements?
 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?
 63.7533 Can I use emission credits earned from implementation of energy conservation measures to comply with this subpart?

Continuous Compliance Requirements

- 63.7535 How do I monitor and collect data to demonstrate continuous compliance?
 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?
 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

Notification, Reports, and Records

- 63.7545 What notifications must I submit and when?
 63.7550 What reports must I submit and when?
 63.7555 What records must I keep?
 63.7560 In what form and how long must I keep my records?

Other Requirements and Information

- 63.7565 What parts of the General Provisions apply to me?
 63.7570 Who implements and enforces this subpart?
 63.7575 What definitions apply to this subpart?

Tables to Subpart DDDDD of Part 63

- Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters
 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)
 Table 3 to Subpart DDDDD of Part 63—Work Practice Standards
 Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

- Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements
 Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements
 Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits
 Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance
 Table 9 to Subpart DDDDD of Part 63—Reporting Requirements
 Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD
 Table 11 to Subpart DDDDD of Part 63—Toxic Equivalency Factors for Dioxins/Furans
 Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

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, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.761 (subpart HH of this part, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities).

§ 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 at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory 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, as defined in § 63.7575, located at a major source.

(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 (m) of this section are not subject to this subpart.

(a) An electric utility steam generating unit.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(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 subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see § 63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part (i.e., another National Emission Standards for Hazardous Air Pollutants in 40 CFR part 63).

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, provided that at least 50 percent of the heat input to the boiler is provided by the gas stream that is regulated under another subpart.

(j) Temporary boilers as defined in this subpart.

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

(l) Any boiler specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers).

§ 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 May 20, 2011 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 March 21, 2014.

(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.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.

Emission Limitations and Work Practice Standards

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

The subcategories of boilers and process heaters, as defined in § 63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers designed to burn biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners/Dutch Ovens designed to burn biomass/bio-based solid.

(g) Fuel Cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn biomass/bio-based solid.

(i) Units designed to burn solid fuel.

(j) Units designed to burn liquid fuel.

(k) Units designed to burn liquid fuel in non-continental States or territories.

(l) Units designed to burn natural gas, refinery gas or other gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b) and (c) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 12 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. If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before May 20, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until March 21, 2014. On and after March 21, 2014, you must comply with the emission limits in Table 1 to this subpart.

(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 EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that 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.

(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(c) Limited-use boilers and process heaters must complete a biennial tune-up as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 to this subpart, the annual tune-up requirement in Table 3 to this subpart, or the operating limits in Table 4 to this subpart. Major sources that have limited-use boilers and process heaters must complete an energy assessment as specified in Table 3 to this subpart if the source has other existing boilers subject to this subpart that are not limited-use boilers.

§ 63.7501 How can I assert an affirmative defense if I exceed an emission limitations during a malfunction?

In response to an action to enforce the emission limitations and operating limits set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for exceeding such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(4) If the excess emissions resulted from a bypass of control equipment or

a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) *Notification.* The owner or operator of the facility experiencing an exceedance of its emission limitat(s) during a malfunction shall notify the Administrator by telephone or facsimile (fax) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.7500 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

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) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS) or continuous opacity monitoring system (COMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride or mercury using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance for hydrogen chloride or mercury using performance testing, if subject to an applicable emission limit listed in Table 1, 2, or 12 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits (including the use of continuous parameter monitoring system), or with a CEMS, or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or continuous parameter monitoring system. 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 (including CEMS, COMS, or continuous parameter monitoring system), you must develop, and submit to the delegated 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. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and COMS prepared under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525.

(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)(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) (as applicable in Table 10 to this subpart), (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 applicable emission limits in Tables 1 or 2 of this subpart through performance testing, your initial compliance requirements include conducting performance 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 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. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected sources that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(b) For affected sources that elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 of this subpart for hydrogen chloride 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 is subject to a carbon monoxide limit, your initial compliance demonstration for carbon monoxide is to conduct a performance test for carbon monoxide according to Table 5 to this subpart. Your initial compliance demonstration for carbon monoxide also includes conducting a performance evaluation of your continuous oxygen monitor according to § 63.7525(a).

(d) If your boiler or process heater subject to a PM limit has a heat input capacity greater than 250 MMBtu per hour and combusts coal, biomass, or residual oil, your initial compliance demonstration for PM is to conduct a performance evaluation of your continuous emission monitoring system for PM according to § 63.7525(b). Boilers and process heaters that use a continuous emission monitoring system for PM are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section.

(e) For existing affected sources, you must demonstrate initial compliance, as specified in paragraphs (a) through (d) of this section, 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 after June 4, 2010, you must demonstrate initial compliance with the emission limits no later than November 16, 2011 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Table 12 to this subpart that is less stringent than (that is, higher than) the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than September 17, 2014.

(g) For affected sources that ceased burning solid waste consistent with § 63.7495(e) and for which your initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before

you commence or recommence combustion of solid waste.

§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except those for dioxin/furan emissions, unless you follow the requirements listed in paragraphs (b) through (e) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (e) of this section. Annual performance testing for dioxin/furan emissions is not required after the initial compliance demonstration.

(b) You can conduct performance tests less often for a given pollutant if your performance tests for the pollutant for at least 2 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 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually.

(c) If your boiler or process heater continues to meet the emission limit for the pollutant, you may choose to conduct performance 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 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum Hg input level is waived unless the stack test is conducted for Hg.

(d) If a performance test shows emissions exceeded 75 percent of the emission limit for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests

over a consecutive 2-year period show compliance.

(e) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual or biennial performance tune-up according to § 63.7540(a)(10) and (a)(11), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up.

(f) If you demonstrate compliance with the mercury or hydrogen chloride based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1, 2, or 12 of this subpart. 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. If 12 consecutive monthly fuel analyses demonstrate compliance, you may request decreased fuel analysis frequency by applying to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(g) You must report the results of performance tests and the associated initial fuel analyses within 90 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?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on representative performance of the affected source for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific

conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions 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 performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(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 comply with the minimum applicable sampling times or volumes specified in Tables 1, 2, and 12 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter concentrations, the measured hydrogen chloride 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, fuel specification, and procedures must I use?

(a) For solid, liquid, and gas 2 (other) fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury and hydrogen chloride in Tables 1, 2, or 12 to this subpart. Gaseous and liquid fuels are exempt from requirements in paragraphs (c) and (d) of this section and Table 6 of this subpart.

(b) You must develop and submit a site-specific fuel monitoring 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 conduct an initial compliance demonstration.

(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.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for hydrogen sulfide and mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable. You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels other than natural gas or refinery gas that are complying with the limits for units designed to burn gas 2 (other) fuels.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements

in paragraphs (g)(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 conduct an initial compliance demonstration.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than natural gas or refinery gas 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 specification analysis.

(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6. 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. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of hydrogen sulfide and 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.

(h) You must obtain a single fuel sample for each other gas 1 fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, and of hydrogen sulfide, in units of parts per million, by volume, dry basis, of each sample for each gas 1 fuel type

according to the procedures in Table 6 to this subpart.

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

(a) As an alternative to meeting the requirements of § 63.7500 for particulate matter, hydrogen chloride, 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 emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) 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, hydrogen chloride, or mercury emissions among existing units 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 May 20, 2011 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 May 20, 2011.

(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 using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

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

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Hm) \div \sum_{i=1}^n Hm \quad (Eq. 1)$$

Where:

AveWeightedEmissions = Average weighted emissions for particulate matter, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input.
 Er = Emission rate (as determined during the initial compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by

performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).
 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.
 1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat

input capacity of one or more boilers that generate 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, hydrogen chloride, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Sm \times Cfi) \div \sum_{i=1}^n (Sm \times Cfi) \quad (\text{Eq. 2})$$

Where:

AveWeightedEmissions = Average weighted emission level for PM, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input.
 Er = Emission rate (as determined during the most recent compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or

by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).
 Sm = Maximum steam generation capacity by unit, i, in units of pounds.
 Cfi = 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.
 1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, 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 average weighted emission rate for that month using the actual heat input for each existing unit participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Hb) \div \sum_{i=1}^n Hb \quad (\text{Eq. 3})$$

Where:

AveWeightedEmissions = Average weighted emission level for particulate matter, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input, for that calendar month.
 Er = Emission rate (as determined during the most recent compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input.

Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).
 Hb = The heat input for that calendar month to unit, i, in units of million Btu.
 n = Number of units participating in the emissions averaging option.

1.1 = 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 average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Sa \times Cfi) \div \sum_{i=1}^n (Sa \times Cfi) \quad (\text{Eq. 4})$$

Where:

AveWeightedEmissions = average weighted emission level for PM, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input for that calendar month.
 Er = Emission rate (as determined during the most recent compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or

mercury using the applicable equation in § 63.7530(c).
 Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.
 Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.
 1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this

section for each calendar month. 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 calendar month and the previous 11 calendar months.

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

Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)
 Eri = Monthly weighted average, for calendar month "i" (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

(g) You must develop, and submit to the applicable delegated authority for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of May 20, 2011 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, hydrogen chloride, 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 delegated 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 load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) The delegated 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 delegated 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) For a group of two or more existing affected units, each of which vents through a single common stack, you may average particulate matter, hydrogen chloride, or mercury emissions to demonstrate compliance with the limits for that pollutant 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 the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, 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 of this section.

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

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).

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

Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified in § 63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; 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) 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 is subject to a carbon monoxide emission limit in Table 1, 2, or 12 to this subpart, you must install, operate, and maintain a continuous oxygen monitor according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in § 63.7495. The oxygen level shall be monitored at the outlet of the boiler or process heater.

(1) Each CEMS for oxygen (O₂ CEMS) must be installed, operated, and maintained according to the applicable procedures under Performance Specification 3 at 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 O₂ CEMS according

to the requirements in § 63.8(e) and according to Performance Specification 3 at 40 CFR part 60, appendix B.

(3) Each O₂ CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) The O₂ CEMS data must be reduced as specified in § 63.8(g)(2).

(5) You must calculate and record 12-hour block average concentrations for each operating day.

(6) For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, excluding data collected during periods when the monitoring system malfunctions or is out of control, during associated repairs, and during required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments). Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. Any period for which the monitoring system malfunctions or is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Periods when data are unavailable because of required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments) do not constitute monitoring deviations.

(b) If your boiler or process heater has a heat input capacity of greater than 250 MMBtu per hour 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 (5) of this section.

(1) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(9).

(2) For a new unit, the initial performance evaluation shall be completed no later than November 16, 2011 or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than September 17, 2014.

(3) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission concentration shall be calculated using

EPA Reference Method 19 at 40 CFR part 60, appendix A-7.

(4) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(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.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required to install and operate a PM CEMS or a bag leak detection system, you must install, operate, certify and maintain each 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 Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(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 a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily 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 according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.

(1) The continuous parameter monitoring system 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 a required calculation constitutes a deviation from the monitoring requirements.

(4) You must determine the 4-hour block average of all recorded readings, except as provided in paragraph (d)(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 monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must install 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 no greater than 2 percent of the expected flow rate.

(3) You must minimize the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually. (f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (e.g., PM scrubber pressure drop).

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

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (e.g., check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in your monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install 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) Conduct a performance evaluation of the pH monitoring system in accordance with your monitoring plan at least once each process operating day.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan

at the time of each performance test but no less frequently than quarterly.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

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

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CEMS and 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 the bag leak detection system as specified in paragraphs (j)(1) through (7) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute particulate matter loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see § 63.14).

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

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert

when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it can be easily heard or seen by plant operating personnel.

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

(k) For each unit that meets the definition of limited-use boiler or process heater, you must monitor and record the operating hours per year for that unit.

§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. If applicable, you must also install, and operate, maintain all applicable CMS (including CEMS, COMS, and continuous parameter monitoring systems) according to § 63.7525.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(3) 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 (b)(1) and (2) of this section, as applicable. As specified in § 63.7510(a), if your affected source burns a single type of fuel (excluding supplemental fuels used for unit startup, shutdown, or transient flame stabilization), you are not required to perform the initial fuel analysis for each type of fuel burned in your boiler or process heater. However, if you switch fuel(s) and cannot show that the new fuel(s) do (does) not increase the chlorine or mercury input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(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 fuel analysis for hydrogen chloride, 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.

$$Cl_{input} = \sum_{i=1}^n (C_i \times Q_i) \quad (\text{Eq. } 7)$$

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 fuel analysis using the procedures in paragraphs (b)(2)(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.

$$Mercury_{input} = \sum_{i=1}^n (HG_i \times Q_i) \quad (\text{Eq. } 8)$$

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 (b)(3)(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, hydrogen chloride, 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 hydrogen chloride 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 operated with a wet scrubber, you must establish the minimum voltage and secondary amperage (or total power input), as defined in § 63.7575, as your operating limits during the three-run performance test. (These operating limits do not apply to electrostatic precipitators that are operated as dry controls without a wet scrubber.)

(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) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test.

(v) The operating limit for boilers or process heaters with fabric filters that 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 (4) 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.

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

Where:

$P90$ = 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 hydrogen chloride, the hydrogen chloride 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 hydrogen chloride.

$$HCl = \sum_{i=1}^n (Ci90 \times Qi \times 1.028) \quad (\text{Eq. 10})$$

Where:

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

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 9 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.
n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of hydrogen chloride 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.

$$\text{Mercury} = \sum_{i=1}^n (Hgi90 \times Qi) \quad (\text{Eq. 11})$$

Where:

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

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 9 of this section.

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

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 less than 10 million Btu per hour, 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 include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and 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).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i). If the mercury and hydrogen sulfide constituents in the gaseous fuels will never exceed the specifications included in the definition, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas

specifications outlined in the definition of other gas 1 fuels. If your gas constituents could vary above the specifications, you will conduct monthly testing according to the procedures in § 63.7521(f) through (i) and § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g).

(h) If you own or operate a unit subject emission limits in Tables 1, 2, or 12 of this subpart, you must minimize the unit's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a unit of similar design if manufacturer's recommended procedures are not available.

§ 63.7533 Can I use emission credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent steam output-based emission limits, instead of the heat input-based limits, listed in Tables 1 and 2 of this subpart and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using emission reduction credits according to the procedures in this section. Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the

emission credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the emission credit according to the procedures in paragraphs (b) through (f) of this section.

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.*, fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which emission credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. Use actual, not estimated, use data, if possible and data that are current and timely.

(c) Emissions credits can be generated if the energy conservation measures were implemented after January 14, 2011 and if sufficient information is

available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate emissions averaging credits:

(i) Energy conservation measures implemented on or before January 14, 2011, unless the level of energy demand reduction is increased after January 14, 2011, in which case credit will be allowed only for change in demand reduction achieved after January 14, 2011.

(ii) Emission credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 12 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 14, 2011. Credits shall be calculated using Equation 12 of this section as follows:

(i) The overall equation for calculating credits is:

$$Credits = \sum_{i=1}^n EIS_{actual} \div EI_{baseline} \quad (\text{Eq. 12})$$

Where:

Credits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, million Btu per year.

EIS_{actual} = Energy Input Savings for each energy conservation measure implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input for the affected boiler, million Btu.

n = Number of energy conservation measures included in the emissions credit for the affected boiler.

(d) The owner or operator shall develop and submit for approval an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an emissions credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the emissions credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. You must submit the implementation plan for emission credits to the applicable delegated authority for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the emission credit approach.

(e) The emissions rate from each existing boiler participating in the emissions credit 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.

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

(1) You must use Equation 13 of this section to demonstrate that the emissions from the affected boiler participating in the emissions credit compliance approach do not exceed the

emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - EC) \quad (\text{Eq. 13})$$

Where:

E_{adj} = Emission level adjusted applying the emission credits earned, lb per million Btu steam output for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output for the affected boiler.

EC = Emission credits from equation 12 for the affected boiler.

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) You must operate the monitoring system and collect data at all required intervals at all times that the affected source is operating, except for periods of monitoring system malfunctions or out of control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks and required zero and span adjustments. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to effect monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs

associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments, failure to collect required data is a deviation of the monitoring requirements.

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications 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 (11) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new 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 hydrogen chloride 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 test (if you demonstrate compliance through performance testing).

(3) If you demonstrate compliance with an applicable hydrogen chloride emission limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the hydrogen chloride 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 hydrogen chloride emission rate from your boiler or process heater under these new conditions using Equation 10 of § 63.7530. The recalculated hydrogen chloride emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable hydrogen chloride 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 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater 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 hydrogen chloride 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(b).

(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)(5)(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 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 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(b).

(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) [Reserved].

(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 PM 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 PM CEMS according to the applicable requirements of § 60.13, and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, PM and oxygen (or carbon dioxide) 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 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. 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 CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to EPA by successfully submitting the data electronically into EPA's Central Data Exchange by using the Electronic Reporting Tool (see http://www.epa.gov/ttn/chief/ert/ert_tool.html/).

(10) If your boiler or process heater is in either the natural gas, refinery gas, other gas 1, or Metal Process Furnace subcategories and has 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. This requirement does not apply to limited-use boilers and process heaters, as defined in § 63.7575.

(j) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, but you must inspect each burner at least once every 36 months);

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

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

(iv) Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications, if available;

(v) Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made); and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of carbon monoxide in the effluent stream in parts per million by volume, and oxygen in volume percent, 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, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section to demonstrate continuous compliance.

(12) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup.

(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.

(c) If you elected to demonstrate that the unit meets the specifications for hydrogen sulfide and mercury for the other gas 1 subcategory and you cannot submit a signed certification under § 63.7545(g) because the constituents could exceed the specifications, you must conduct monthly fuel specification testing of the gaseous fuels, according to the procedures in § 63.7521(f) through (i).

§ 63.7541 How do I demonstrate continuous compliance under the emissions 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) and (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 non-affected 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.

(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 to the delegated authority 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 May 20, 2011, you must submit an Initial Notification not later than 120 days after May 20, 2011.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after May 20, 2011, 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 60 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 the initial compliance demonstration for each affected source, 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 all performance test and/or other initial compliance demonstrations for the affected source according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable.

(1) A description of the affected unit(s) including identification of which subcategory the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit, 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 § 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of § 241.3, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) A summary of the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable emission standard in Table 1, 2, or 12 to this subpart.

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

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using emission credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on May 20, 2011.

(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.

(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the requirements in § 63.7540(a)(10) to conduct an annual or biennial tune-up, as applicable, of each unit."

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

(iii) Except for units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: "No secondary materials that are solid waste were combusted in any affected unit."

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each 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.

(g) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(h) If you intend to switch fuels, and this fuel switch may result in the applicability of a different subcategory, you must provide 30 days prior notice of the date upon which you will switch fuels. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that will switch fuels, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable standards.

(4) The date upon which you will commence the fuel switch.

§ 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. For units that are subject only to a requirement to conduct an annual or biennial tune-up according to § 63.7540(a)(10) or (a)(11), respectively, and not subject to emission limits or operating limits, you may submit only an annual or biennial

compliance report, as applicable, as specified in paragraphs (b)(1) through (5) of this section, instead of a semi-annual compliance report.

(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 (or 1 or 2 year, as applicable, if submitting an annual or biennial compliance report) 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. The first annual or biennial compliance report must be postmarked no later than January 31.

(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. Annual and biennial compliance reports must cover the applicable one or two year periods from January 1 to 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. Annual and biennial compliance reports must be postmarked no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the delegated authority has established dates for submitting semiannual reports pursuant to § 70.6(a)(3)(iii)(A) or § 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the delegated 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 (13) 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 (or annual or biennial) 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 for affected sources subject to an emission limit, a summary of any fuel analyses associated with performance tests, and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests, a comparison of the emission level you achieved in the last 2 performance tests to the 75 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 performance test that could increase emissions.

(6) A signed statement indicating that you burned no new types of fuel in an affected source subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a hydrogen chloride emission limit, 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 hydrogen chloride emission rate using Equation 10 of § 63.7530 that demonstrates that your source is still meeting the emission limit for hydrogen chloride emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 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 in an affected source subject to an emission limit and you cannot

demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 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) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for affected sources subject to emission limits, and any fuel specification analyses conducted according to § 63.7521(f) and § 63.7530(g).

(9) 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.

(10) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and continuous parameter monitoring systems, 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.

(11) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(12) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual or biennial tune-up according to § 63.7540(a)(10) or (a)(11), respectively. Include the date of the most recent burner inspection if it was not done annually or biennially and was delayed until the next scheduled unit shutdown.

(13) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(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.

(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 control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's 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 part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by § 70.6(a)(3)(iii)(A) or § 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 § 70.6(a)(3)(iii)(A) or § 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 delegated authority.

(g) [Reserved]

(h) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert_tool.html/) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

§ 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 tests, fuel analyses, or other compliance demonstrations and performance

evaluations as required in § 63.10(b)(2)(viii).

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

(1) Records described in § 63.10(b)(2)(vii) 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.

(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, pH, and operating load, 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 in Table 1, 2 or 12 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (8) 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 § 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 § 241.3(b)(4), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in § 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c), you must keep a record that 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 that meets the definition of limited-use boiler or process heater.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the hydrogen chloride 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 hydrogen chloride emission rates, using Equation 10 of § 63.7530, that were done to demonstrate compliance with the hydrogen chloride emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or hydrogen chloride 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 hydrogen chloride emission rate, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate 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 § 63.7515(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 75 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) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.

(8) Records of actions taken during periods of malfunction to minimize emissions in accordance with the

general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(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 monthly records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.7541.

(f) If you elect to use emission credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specifications for hydrogen sulfide and mercury for the other gas 1 subcategory and you cannot submit a signed certification under § 63.7545(g) because the constituents could exceed the specifications, you must maintain monthly records of the calculations and results of the fuel specifications for mercury and hydrogen sulfide in Table 6.

(h) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuel that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, or other gas 1 fuel, you must keep records of the total hours per calendar year that alternative fuel is burned.

§ 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, or they must be accessible from on site (for example, through a computer network), 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 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 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, 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, in § 63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

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.

Benchmarking means a process of comparison against standard or average.

Biomass or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (*e.g.*, trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, 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 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 annual gas volume 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. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

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

Calendar year means the period beginning January 1 and December 31, inclusive, for a given year.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-

bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes synthetic fuels derived from coal for creating useful heat, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. 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 steam and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in 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 2 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.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM D396 (incorporated by reference, see § 63.14).

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. A dry scrubber is a dry control system.

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 (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Emission credit means emission reductions above those required by this subpart. Emission credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Shutdowns cannot be used to generate credits.

Energy assessment means the following only as this term is used in Table 3 to this subpart.

(1) Energy assessment for facilities with affected boilers and process heaters using less than 0.3 trillion Btu per year heat input will be one day in length maximum. The boiler system and energy use system accounting for at least 50 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing a one-day energy assessment.

(2) The Energy assessment for facilities with affected boilers and process heaters using 0.3 to 1.0 trillion Btu per year will be 3 days in length maximum. The boiler system and any energy use system accounting for at least 33 percent of the energy output

will be evaluated to identify energy savings opportunities, within the limit of performing a 3-day energy assessment.

(3) In the Energy assessment for facilities with affected boilers and process heaters using greater than 1.0 trillion Btu per year, the boiler system and any energy use system accounting for at least 20 percent of the energy output will be evaluated to identify energy savings opportunities.

Energy management practices means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

Energy use system includes, but is not limited to, process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot heater systems; building envelop; and lighting.

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

(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, hydrogen chloride, hydrogen sulfide) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart 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. A fabric filter is a dry control system.

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.

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.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

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.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

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 degrees Fahrenheit (99 degrees Celsius). *Hot water heater* also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler.

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

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable limit of no more than 876 hours per year of operation.

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, based on the total annual heat input to the unit.

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

Load fraction means the actual heat input of the boiler or process heater divided by the average operating load determined according to Table 7 to this subpart.

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

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction (percent) multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart

during the most recent performance test demonstrating compliance with the applicable emission limits.

Minimum pressure drop means the lowest hourly 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 the lowest hourly average sorbent liquid pH measured at the inlet to 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 liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop 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 load fraction (percent) multiplied by the lowest hourly average sorbent 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 total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current 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 in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 mega joules (MJ) per dry standard cubic

meter (910 and 1,150 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C₃H₈.

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

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed the maximum concentration of 40 micrograms/cubic meters of mercury and 4 parts per million, by volume, of hydrogen sulfide.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved 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. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. 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, 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 come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. 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 or other solid fossil fuel is introduced into an air stream that carries the coal to the

combustion chamber of the boiler where it is fired in suspension.

Qualified energy assessor means:

(1) someone who has demonstrated capabilities to evaluate a set of the typical energy savings opportunities available in opportunity areas for steam generation and major energy using systems, including, but not limited to:

- (i) Boiler combustion management.
- (ii) Boiler thermal energy recovery, including
 - (A) Conventional feed water economizer,
 - (B) Conventional combustion air preheater, and
 - (C) Condensing economizer.
- (iii) Boiler blowdown thermal energy recovery.
- (iv) Primary energy resource selection, including

- (A) Fuel (primary energy source) switching, and
- (B) Applied steam energy versus direct-fired energy versus electricity.
- (v) Insulation issues.
- (vi) Steam trap and steam leak management.
- (vi) Condensate recovery.
- (viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

- (i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.
- (ii) Familiarity with operating and maintenance practices for steam or process heating systems.
- (iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.
- (iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.
- (v) Boiler-steam turbine cogeneration systems.
- (vi) Industry specific steam end-use systems.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined in ASTM D396-10 (incorporated by reference, see § 63.14(b)).

Responsible official means responsible official as defined in § 70.2.

Solid fossil fuel includes, and is not limited to, coal, coke, petroleum coke, and tire derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Steam output means (1) for a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output, and (2) for a boiler that cogenerates process steam and electricity (also known as combined heat and power (CHP)), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour).

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 under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. 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 dry quickly 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 by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

- (1) The equipment is attached to a foundation.
- (2) The boiler or a replacement remains at a location for more than 12 consecutive months. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.
- (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility

for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

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/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels; with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment and gas supply emergencies.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, less than 10 percent biomass/bio-based solid fuel, and less than 10 percent liquid fuels on an annual heat input basis.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total

of 48 hours during any calendar year or during periods of maintenance, operator training, or testing of liquid fuel, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater designed to burn liquid fuel located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns any solid fuel alone or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Voluntary Consensus Standards or VCS mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English.

Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, <http://www.iso.org/iso/home.htm>), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 <http://www.stadards.org.au>), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, <http://www.bsigroup.com>), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga,

Ontario L4W 5N6, Canada, 800-463-6727, <http://www.csa.ca>), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium +32 2 550 08 11, <http://www.cen.eu/cen>), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214-230, <http://www.vdi.eu>). The types of standards that are not considered VCS are standards developed by: The United 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 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 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 or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

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 Clean Air Act.

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^a

[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 . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. Particulate Matter	0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	0.0011; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.0022 lb per MMBtu of heat input.	0.0021	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 60 liters per run.
	c. Mercury	3.5E-06 lb per MMBtu of heat input.	3.4E-06	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 2 dscm.
2. Units designed to burn pulverized coal/solid fossil fuel.	a. Carbon monoxide (CO)	12 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.01	1 hr minimum sampling time, use a span value of 30 ppmv.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	2.8E-12 (TEQ)	Collect a minimum of 4 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel.	a. CO	6 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.005	1 hr minimum sampling time, use a span value of 20 ppmv.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	2.8E-12 (TEQ)	Collect a minimum of 4 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO	18 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.02	1 hr minimum sampling time, use a span value of 40 ppmv.
	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E-12 (TEQ)	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn biomass/bio-based solids.	a. CO	160 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13	1 hr minimum sampling time, use a span value of 400 ppmv.
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.4E-12 (TEQ)	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO	260 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.18	1 hr minimum sampling time, use a span value of 500 ppmv.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E-11 (TEQ)	Collect a minimum of 4 dscm per run.
7. Suspension burners/ Dutch Ovens designed to burn biomass/bio-based solids.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.45	1 hr minimum sampling time, use a span value of 1000 ppmv.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E-10 (TEQ)	Collect a minimum of 4 dscm per run.
8. Fuel cells designed to burn biomass/bio-based solids.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.23	1 hr minimum sampling time, use a span value of 1000 ppmv.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	2.86E-12 (TEQ)	Collect a minimum of 4 dscm per run.
9. Hybrid suspension/grate units designed to burn biomass/bio-based solids.	a. CO	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.84	1 hr minimum sampling time, use a span value of 3000 ppmv.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS ^a—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 . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
10. Units designed to burn liquid fuel.	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E-10 (TEQ)	Collect a minimum of 4 dscm per run.
	a. Particulate Matter	0.0013 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	0.001; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.00033 lb per MMBtu of heat input.	0.0003	For M26A: Collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	2.1E-07 lb per MMBtu of heat input.	0.2E-06	Collect enough volume to meet an in-stack detection limit data quality objective of 0.10 ug/dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.0026	1 hr minimum sampling time, use a span value of 3 ppmv.
11. Units designed to burn liquid fuel located in non-continental States and territories.	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.6E-12 (TEQ)	Collect a minimum of 4 dscm per run.
	a. Particulate Matter	0.0013 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	0.001; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.00033 lb per MMBtu of heat input.	0.0003	For M26A: Collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.8E-07 lb per MMBtu of heat input.	8.0E-07	For M29, collect a minimum of 3 dscm per run; for M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 3 dscm.
	d. CO	51 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.043	1 hr minimum sampling time, use a span value of 100 ppmv.
12. Units designed to burn gas 2 (other) gases.	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.6E-12(TEQ)	Collect a minimum of 3 dscm per run.
	a. Particulate Matter	0.0067 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	.004; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input.	.003	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS ^a—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 . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
	c. Mercury	7.9E-06 lb per MMBtu of heat input.	2.0E-07	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 2 dscm. 1 hr minimum sampling time, use a span value of 10 ppmv. Collect a minimum of 4 dscm per run
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.002	
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.1E-12 (TEQ)	

^a If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before May 20, 2011, you may comply with the emission limits in Table 12 to this subpart until March 21, 2014. On and after March 21, 2014, you must comply with the emission limits in Table 1 to this subpart.

^b Incorporated by reference, see § 63.14.

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 . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. Particulate Matter	0.039 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	0.038; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.035 lb per MMBtu of heat input.	0.04	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	4.6E-06 lb per MMBtu of heat input.	4.5E-06	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^a collect a minimum of 2 dscm.
2. Pulverized coal units designed to burn pulverized coal/solid fossil fuel.	a. CO	160 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.14	1 hr minimum sampling time, use a span value of 300 ppmv.
	b. Dioxins/Furans	0.004 ng/dscm (TEQ) corrected to 7 percent oxygen.	3.7E-12 (TEQ)	Collect a minimum of 4 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel.	a. CO	270 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.25	1 hr minimum sampling time, use a span value of 500 ppmv.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	2.8E-12 (TEQ)	Collect a minimum of 4 dscm per run.

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 sub-category . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
4. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO	82 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.08	1 hr minimum sampling time, use a span value of 200 ppmv
	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E-12 (TEQ)	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn biomass/bio-based solid.	a. CO	490 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.35	1 hr minimum sampling time, use a span value of 1000 ppmv.
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.4E-12 (TEQ)	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn biomass/bio-based solid.	a. CO	430 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.28	1 hr minimum sampling time, use a span value of 850 ppmv.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E-11(TEQ)	Collect a minimum of 4 dscm per run.
7. Suspension burners/ Dutch Ovens designed to burn biomass/bio-based solid.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.45	1 hr minimum sampling time, use a span value of 1000 ppmv.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E-10 (TEQ)	Collect a minimum of 4 dscm per run.
8. Fuel cells designed to burn biomass/bio-based solid.	a. CO	690 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.34	1 hr minimum sampling time, use a span value of 1300 ppmv.
	b. Dioxins/Furans	4 ng/dscm (TEQ) corrected to 7 percent oxygen.	3.5E-09 (TEQ)	Collect a minimum of 4 dscm per run.
9. Hybrid suspension/grate units designed to burn biomass/bio-based solid.	a. CO	3,500 ppm by volume on a dry basis corrected to 3 percent oxygen.	2.0	1 hr minimum sampling time, use a span value of 7000 ppmv.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E-10 (TEQ)	Collect a minimum of 4 dscm per run.
10. Units designed to burn liquid fuel.	a. Particulate Matter	0.0075 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	0.0073; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.00033 lb per MMBtu of heat input.	0.0003	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 200 liters per run.
	c. Mercury	3.5E-06 lb per MMBtu of heat input.	3.3E-06	For M29, collect a minimum of 1 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 ^a collect a minimum of 2 dscm.
	d. CO	10 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.0083	1 hr minimum sampling time, use a span value of 20 ppmv.
	e. Dioxins/Furans	4 ng/dscm (TEQ) corrected to 7 percent oxygen.	9.2E-09 (TEQ)	Collect a minimum of 1 dscm per run.

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 . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
11. Units designed to burn liquid fuel located in non-continental States and territories.	a. Particulate Matter	0.0075 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	0.0073; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.00033 lb per MMBtu of heat input.	0.0003	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 200 liters per run.
	c. Mercury	7.8E-07 lb per MMBtu of heat input.	8.0E-07	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^a collect a minimum of 2 dscm.
	d. CO	160 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13	1 hr minimum sampling time, use a span value of 300 ppmv.
	e. Dioxins/Furans	4 ng/dscm (TEQ) corrected to 7 percent oxygen.	9.2E-09 (TEQ)	Collect a minimum of 1 dscm per run.
12. Units designed to burn gas 2 (other) gases.	a. Particulate Matter	0.043 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	0.026; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input.	0.001	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	1.3E-05 lb per MMBtu of heat input.	7.8E-06	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^a collect a minimum of 2 dscm.
	d. CO	9 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.005	1 hr minimum sampling time, use a span value of 20 ppmv.
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen.	3.9E-11 (TEQ)	Collect a minimum of 4 dscm per run.

^a Incorporated by reference, see § 63.14.

As stated in § 63.7500, you must comply with the following applicable work practice standards:

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

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour or a limited use boiler or process heater.	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.

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

If your unit is . . .	You must meet the following . . .
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 or process heater annually as specified in § 63.7540.
3. An existing boiler or process heater located at a major source facility	<p>Must have a one-time energy assessment performed on the major source facility by qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. The energy assessment must include:</p> <ul style="list-style-type: none"> a. A visual inspection of the boiler or process heater system. b. An evaluation of operating characteristics of the facility, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints, c. An inventory of 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 review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, f. A list of major energy conservation measures, g. A list of the energy savings potential of the energy conservation measures identified, and h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
4. An existing or new unit subject to emission limits in Tables 1, 2, or 12 of this subpart..	Minimize the unit's startup and shutdown periods following the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.

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 PM scrubber control	Maintain the 12-hour block average pressure drop and the 12-hour block average liquid flow rate at or above the lowest 1-hour average pressure drop and the lowest 1-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.
2. Wet acid gas (HCl) scrubber control	Maintain the 12-hour block average effluent pH at or above the lowest 1-hour average pH and the 12-hour block average liquid flow rate at or above the lowest 1-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on units not required to install and operate a PM CEMS.	<ul style="list-style-type: none"> a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or b. 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.
4. Electrostatic precipitator control on units not required to install and operate a PM CEMS.	<ul style="list-style-type: none"> a. This option is for boilers and process heaters that operate dry control systems (<i>i.e.</i>, an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or b. This option is only for boilers and process heaters not subject to PM CEMS or continuous compliance with an opacity limit (<i>i.e.</i>, COMS). Maintain the minimum total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.

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 . . .
6. Any other add-on air pollution control type on units not required to install and operate a PM CEMS.	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).
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance test.
9. Continuous Oxygen Monitoring System	For boilers and process heaters subject to a carbon monoxide emission limit that demonstrate compliance with an O ₂ CEMS as specified in § 63.7525(a), maintain the oxygen level of the stack gas such that it is not below the lowest hourly average oxygen concentration measured during the most recent CO performance test.

As stated in § 63.7520, you must _____ for performance testing for existing, new
comply with the following requirements _____ 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. b. Determine velocity and volumetric flow-rate of the stack gas.. c. Determine oxygen or carbon dioxide concentration of the stack gas. d. Measure the moisture content of the stack gas	Method 1 at 40 CFR part 60, appendix A-1 of this chapter. Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter. Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. ^a Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
2. Hydrogen chloride	e. Measure the particulate matter emission concentration. f. Convert emissions concentration to lb per MMBtu emission rates. a. Select sampling ports location and the number of traverse points. b. Determine velocity and volumetric flow-rate of the stack gas. c. Determine oxygen or carbon dioxide concentration of the stack gas. d. Measure the moisture content of the stack gas	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter. Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter. Method 1 at 40 CFR part 60, appendix A-1 of this chapter. Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter. Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981. ^a Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
3. Mercury	e. Measure the hydrogen chloride emission concentration. f. Convert emissions concentration to lb per MMBtu emission rates. a. Select sampling ports location and the number of traverse points. b. Determine velocity and volumetric flow-rate of the stack gas. c. Determine oxygen or carbon dioxide concentration of the stack gas. d. Measure the moisture content of the stack gas	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter. Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter. Method 1 at 40 CFR part 60, appendix A-1 of this chapter. Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter. Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981. ^a Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
4. CO	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 60, appendix B of this chapter, or ASTM Method D6784. ^a
	f. Convert emissions concentration to lb per MMBtu emission rates. a. Select the sampling ports location and the number of traverse points.	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter. Method 1 at 40 CFR part 60, appendix A-1 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...
5. Dioxins/Furans	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981. ^a
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a span value of 2 times the concentration of the applicable emission limit.
	a. Select the sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), ^a or ANSI/ASME PTC 19.10-1981. ^a
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	d. Measure the dioxins/furans emission concentration ...	Method 23 at 40 CFR part 60, appendix A-7 of this chapter.
	e. Multiply the measured dioxins/furans emission concentration by the appropriate toxic equivalency factor.	Table 11 of this subpart.

^a Incorporated by reference, see § 63.14.

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 (as defined in § 63.7575) 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 ^a (for coal) or ASTM D6323 ^a (for biomass), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B ^a (for solid samples), EPA SW-846-3020A ^a (for liquid samples), ASTM D2013/D2013M ^a (for coal), ASTM D5198 ^a (for biomass), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 ^a (for coal) or ASTM E711 ^a (for biomass), or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 ^a or ASTM E871, ^a or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D6722 ^a (for coal), EPA SW-846-7471B ^a (for solid samples), or EPA SW-846-7470A ^a (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 ^a (for coal) or ASTM D6323 ^a (for biomass), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B ^a (for solid samples), EPA SW-846-3020A ^a (for liquid samples), ASTM D2013/D2013M ^a (for coal), or ASTM D5198 ^a (for biomass), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 ^a (for coal) or ASTM E711 ^a (for biomass), or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 ^a or ASTM E871, ^a or equivalent.
	f. Measure chlorine concentration in fuel sample.	EPA SW-846-9250, ^a ASTM D6721 ^a (for coal), or ASTM E776 ^a (for biomass), or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	
3. Mercury Fuel Specification for other gas 1 fuels.	a. Measure mercury concentration in the fuel sample.	ASTM D5954, ^a
	b. Convert concentration to unit of micrograms/cubic meter.	ASTM D6350, ^a ISO 6978-1:2003(E), ^a or ISO 6978-2:2003(E) ^a , or equivalent.

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS—Continued

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
4. Hydrogen Sulfide Fuel Specification for other gas 1 fuels.	a. Measure total hydrogen sulfide b. Convert to ppm	ASTM D4084a or equivalent.

^a Incorporated by reference, see § 63.14.

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(b).	(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 lowest hourly average pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b).	(1) Data from the voltage and secondary amperage monitors during the particulate matter or mercury performance test.	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests; (b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
2. Hydrogen Chloride	a. Wet scrubber operating parameters.	i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b).	(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the hydrogen chloride performance test.	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
	b. Dry scrubber operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the hydrogen chloride performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.	(1) Data from the sorbent injection rate monitors and hydrogen chloride or mercury performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. Mercury and dioxins/furans.	a. Activated carbon injection.	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b).	(1) Data from the activated carbon rate monitors and mercury and dioxins/furans performance tests.	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520.	(1) Data from the oxygen monitor specified in § 63.7525(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests;

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
5. Any pollutant for which compliance is demonstrated by a performance test.	a. Boiler or process heater operating load.	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c).	(1) Data from the operating load monitors or from steam generation monitors.	(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your minimum operating limit. (a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

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(c) 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(b).
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(b).
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 minimum sorbent or carbon injection rate as defined in § 63.7575.
6. Electrostatic Precipitator Total Secondary Electric Power Input.	a. Collecting the total secondary electric 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 total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
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(b) or (c) as applicable; and b. Keeping monthly records of fuel use according to § 63.7540(a).

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE—Continued

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
8. Oxygen content	a. Continuously monitor the oxygen content in the combustion exhaust according to § 63.7525(a). b. Reducing the data to 12-hour block averages; and c. Maintain the 12-hour block average oxygen content in the exhaust at or above the lowest hourly average oxygen level measured during the most recent carbon monoxide performance test.
9. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average operating load at or below the operating limit established during the performance test according to § 63.7520(c).

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 (12); 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 3 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 c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in § 63.7550(d); and 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), or otherwise not operating, the report must contain the information in § 63.7550(e).	Semiannually, annually, or biennially according to the requirements in § 63.7550(b).

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) ...	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards..	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes.
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	Yes.

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

Citation	Subject	Applies to subpart DDDDD
§ 63.6(i)	Extension of compliance.	Yes.
§ 63.6(j)	Presidential exemption.	Yes.
§ 63.7(a), (b), (c), and (d)	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(a).
§ 63.7(e)(2)–(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§ 63.8(c)(1)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.7500(a)(3).
§ 63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§ 63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.
§ 63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.
§ 63.8(f)	Use of an alternative monitoring method.	Yes.
§ 63.8(g)	Reduction of monitoring data.	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) for malfunction reporting requirements.
§ 63.10(e) and (f)		Yes.
§ 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.

TABLE 11 TO SUBPART DDDDD OF PART 63—TOXIC EQUIVALENCY FACTORS FOR DIOXINS/FURANS

Dioxin/furan congener	Toxic equivalency factor
2,3,7,8-tetrachlorinated dibenzo-p-dioxin	1
1,2,3,7,8-pentachlorinated dibenzo-p-dioxin	1
1,2,3,4,7,8-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorinated dibenzo-p-dioxin	0.1

TABLE 11 TO SUBPART DDDDD OF PART 63—TOXIC EQUIVALENCY FACTORS FOR DIOXINS/FURANS—Continued

Dioxin/furan congener	Toxic equivalency factor
1,2,3,4,6,7,8-heptachlorinated dibenzo-p-dioxin	0.01
octachlorinated dibenzo-p-dioxin	0.0003
2,3,7,8-tetrachlorinated dibenzofuran	0.1
2,3,4,7,8-pentachlorinated dibenzofuran	0.3
1,2,3,7,8-pentachlorinated dibenzofuran	0.03
1,2,3,4,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,7,8,9-hexachlorinated dibenzofuran	0.1
2,3,4,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,4,6,7,8-heptachlorinated dibenzofuran	0.01
1,2,3,4,7,8,9-heptachlorinated dibenzofuran	0.01
octachlorinated dibenzofuran	0.0003

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
1. Units in all subcategories designed to burn solid fuel	a. Mercury	3.5E-06 lb per MMBtu of heat input.	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^a collect a minimum of 2 dscm.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis.	a. Particulate Matter	0.008 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.004 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis.	a. Particulate Matter	0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.0022 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
4. Units designed to burn pulverized coal/solid fossil fuel.	a. CO	90 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn coal/solid fossil fuel	a. CO	7 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO	30 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
7. Stokers designed to burn biomass/bio-based solids ..	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO	260 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
9. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solids.	a. CO	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
10. Fuel cells designed to burn biomass/bio-based solids.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
11. Hybrid suspension/grate units designed to burn biomass/bio-based solids.	a. CO	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
12. Units designed to burn liquid fuel	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 2 dscm per run.
	b. Hydrogen Chloride	0.0032 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	3.0E-07 lb per MMBtu of heat input.	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^a collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
13. Units designed to burn liquid fuel located in non-contiguous States and territories.	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 2 dscm per run.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
14. Units designed to burn gas 2 (other) gases	b. Hydrogen Chloride	0.0032 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.8E-07 lb per MMBtu of heat input.	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^a collect a minimum of 2 dscm.
	d. CO	51 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
	a. Particulate Matter	0.0067 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input.	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^a collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.

^a Incorporated by reference, see § 63.14.