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National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2006–0790; FRL–9273–5]

RIN 2060–AM44

National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is promulgating national emission standards for control of hazardous air pollutants from two area source categories: Industrial boilers and commercial and institutional boilers. The final emission standards for control of mercury and polycyclic organic matter emissions from coal-fired area source boilers are based on the maximum achievable control technology. The final emission standards for control of hazardous air pollutants emissions from biomass-fired and oil-fired area source boilers are based on EPA's determination as to what constitutes the generally available control technology or management practices.

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

ADDRESSES: EPA established a docket under Docket ID No. EPA–HQ–OAR–2006–0790 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., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Ave., NW., Washington, DC. 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) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. James Eddinger, 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) 541–5426; Fax number (919) 541–5450; e-mail address: *eddinger.jim@epa.gov.*

SUPPLEMENTARY INFORMATION:

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

Btu British thermal unit
CAA Clean Air Act
CBI Confidential Business Information
CEMS Continuous Emission Monitoring System
CFR Code of Federal Regulations
CO Carbon monoxide
ERT Electronic Reporting Tool
FR **Federal Register**
GACT Generally Available Control Technology
HAP Hazardous Air Pollutant
HCl Hydrogen chloride
ICR Information Collection Request
kWh Kilowatt hour
MACT Maximum Achievable Control Technology
MMBtu/h Million Btu per hour
NAICS North American Industry Classification System
NESHAP National Emission Standards for Hazardous Air Pollutants
NO_X Nitrogen oxides
NSPS New Source Performance Standards
PM Particulate matter
$PM_{2.5}$ Fine particulate matter
POM Polycyclic organic matter
ppm Parts per million
RCRA Resource Conservation and Recovery Act
TBtu Trillion British thermal units
tpy Tons per year
SO_2 Sulfur dioxide
UPL Upper Prediction limit
VOC Volatile organic compound

Organization of This Document. The information in this preamble is organized as follows:

I. General Information

A. Does this action apply to me?

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

Category	NAICS code [1]	Examples of regulated entities
Any area source facility using a boiler as defined in this proposed rule	321	Wood product manufacturing.
	11	Agriculture, greenhouses.
	311	Food manufacturing.
	327	Nonmetallic mineral product manufacturing.
	424	Wholesale trade, nondurable goods.
	531	Real estate.
	611	Educational services.
	813	Religious, civic, professional, and similar organizations.
	92	Public administration.
	722	Food services and drinking places.
	62	Health care and social assistance.

[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., is regulated by this action, you should examine the applicability criteria in 40 CFR 63.11193 of subpart JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources). If you have any questions regarding the applicability of this action to a particular entity, consult either the delegated regulatory 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 final action will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of the final 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 section 307(b)(1) of the CAA, 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 (the Court) 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. CAA section 307(d)(7)(B) also provides a mechanism for EPA 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 the 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 20460, with a copy to the person listed in the preceding **FOR FURTHER GENERAL 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 and regulatory approach for this final rule?

Section 112(d) of the CAA requires us to establish NESHAP for both major and area sources of HAP that are listed for regulation under CAA section 112(c). A major source emits or has the potential to emit 10 tpy or more of any single HAP or 25 tpy or more of any combination of HAP. An area source is a HAP-emitting stationary source that is not a major source.

Section 112(k)(3)(B) of the CAA calls for EPA to identify at least 30 HAP which, as the result of emissions from area sources, pose the greatest threat to public health in the largest number of urban areas. EPA implemented this provision in 1999 in the Integrated Urban Air Toxics Strategy (Strategy), (64 FR 38715, July 19, 1999). Specifically, in the Strategy, EPA identified 30 HAP that pose the greatest potential health threat in urban areas, and these HAP are referred to as the "30 urban HAP." CAA section 112(c)(3) requires EPA to list sufficient categories or subcategories of area sources to ensure that area sources representing 90 percent of the emissions of the 30 urban HAP are subject to regulation. A primary goal of the Strategy is to achieve a 75 percent reduction in cancer incidence attributable to HAP emitted from stationary sources.

Under CAA section 112(d)(5), we may elect to promulgate standards or requirements for area sources "which provide for the use of generally available control technologies ["GACT"] or management practices by such sources to reduce emissions of hazardous air pollutants." Additional information on GACT is found in the Senate report on the legislation (Senate Report Number 101–228, December 20, 1989), which describes GACT as:

> * * * methods, practices and techniques which are commercially available and appropriate for application by the sources in the category considering economic impacts and the technical capabilities of the firms to operate and maintain the emissions control systems.

Consistent with the legislative history, we can consider costs and economic impacts in determining GACT, which is particularly important when developing regulations for source categories that may have many small businesses such as these.

Determining what constitutes GACT involves considering the control technologies and management practices that are generally available to the area sources in the source category. We also consider the standards applicable to major sources in the analogous source category to determine if the control technologies and management practices are transferable and generally available to area sources. In appropriate circumstances, we may also consider technologies and practices at area and major sources in similar categories to determine whether such technologies and practices could be considered generally available for the area source categories at issue. Finally, as noted above, in determining GACT for a particular area source category, we consider the costs and economic impacts of available control technologies and management practices on that category.

While GACT may be a basis for standards for most types of HAP emitted from area sources, CAA section 112(c)(6) requires that EPA list categories and subcategories of sources assuring that sources accounting for not less than 90 percent of the aggregate emissions of each of seven specified HAP are subject to standards under CAA sections 112(d)(2) or (d)(4), which require the application of the more stringent MACT. The seven HAP specified in CAA section 112(c)(6) are as follows: Alkylated lead compounds, POM, hexachlorobenzene, mercury, polychlorinated biphenyls (PCBs), 2,3,7,8-tetrachlorodibenzofurans, and 2,3,7,8-tetrachlorodibenzo-p-dioxin.

The CAA section 112(c)(6) list of source categories currently includes industrial coal combustion, industrial oil combustion, industrial wood combustion, commercial coal combustion, commercial oil combustion, and commercial wood combustion. (*See* 63 FR 17849, April 10, 1998.) We listed these source categories under CAA section 112(c)(6) based on the source categories' contribution of mercury and POM. In the documentation for the CAA section 112(c)(6) listing, the commercial fuel combustion categories included institutional fuel combustion. (*See* "1990 Emissions Inventory of Section 112(c)(6) Pollutants, Final Report," April 1998.) As discussed in the preamble to the proposed rule, we concluded we only needed to address mercury emissions from the coal-fueled portion of these categories in order to ensure that 90 percent of the aggregate emissions of mercury would be subject to standards under CAA sections 112(d)(2) or 112(d)(4). (*See* 75 FR 31898, June 4, 2010.) As discussed in this preamble, based on public comments received, we re-examined the emission inventory and the need to address POM emissions from the area source subcategories to meet the CAA section 112(c)(6) 90 percent requirement, and concluded we only need to address POM emissions from the coal-fueled portion of these categories under CAA section 112(d)(2) or 112(d)(4).

With this final rule and the major source boilers rule, we believe that we have subjected to regulation at least 90 percent of the CAA section 112(c)(6) 1990 emissions inventory for mercury and POM. Consequently, we are regulating coal-fired area source boilers under MACT because we need these sources to meet the 90 percent requirement for mercury and POM in CAA section 112(c)(6).

The "MACT" required by CAA sections 112(d)(2) or 112(d)(4) can be based on the emissions reductions achievable through application of measures, processes, methods, systems, or techniques including, but not limited to: (1) Reducing the volume of, or eliminating emissions of, such pollutants through process changes, substitutions of materials, or other modifications; (2) enclosing systems or processes to eliminate emissions; (3) collecting, capturing, or treating such pollutants when released from a process, stack, storage or fugitive emission point; (4) design, equipment, work practices, or operational standards as provided in CAA section 112(h); or (5) a combination of the above.

The MACT floor is the minimum control level allowed for NESHAP and is defined under CAA section 112(d)(3). For new sources, MACT based standards cannot be less stringent than the emission control achieved in practice by the best-controlled similar source, as determined by the Administrator. The MACT based standards for existing sources can be less stringent than standards for new sources, but they cannot be less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources in the category or subcategory (for which the Administrator has emission information) for source categories and subcategories with 30 or more sources, or the best performing 5 sources for categories and subcategories with fewer than 30 sources (CAA section 112(d)(3)(A) and (B)).

Although emission standards are often structured in terms of numerical emissions limits, alternative approaches are sometimes necessary and authorized pursuant to CAA section 112. For example, in some cases, physically measuring emissions from a source may not be practicable due to technological and economic limitations. Section 112(h) of the CAA authorizes the Administrator to promulgate a design, equipment, work practice, or operational standard, or combination thereof, consistent with the provisions of CAA sections 112(d) or (f), in those cases where, in the judgment of the Administrator, it is not feasible to prescribe or enforce an emission standard. Section 112(h)(2) of the CAA provides that the phrase "not feasible to prescribe or enforce an emission standard" includes "the situation in which the Administrator determines that * * * the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations."

As noted above in this section of the preamble, we listed industrial coal combustion, industrial oil combustion, industrial wood combustion, commercial coal combustion, commercial oil combustion, and commercial wood combustion under CAA section 112(c)(6) based on the source categories' contribution of mercury and POM. We listed these same categories under CAA section 112(c)(3) for their contribution of mercury, arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, POM (as 7-PAH (polynuclear aromatic hydrocarbons)), ethylene dioxide, and PCBs.

We have developed final standards to reflect the application of MACT for mercury and POM from coal-fired area source boilers and have applied GACT for the urban HAP noted above for boilers firing other fuels and for urban

HAP (other than mercury and POM) from coal-fired area source boilers.

B. What source categories are affected by the standards?

The source categories affected by the standards are industrial boilers and commercial and institutional boilers. Both source categories were included in the area source list published on July 19, 1999 (64 FR 38721). The inclusion of these two source categories on the CAA section 112(c)(3) area source category list is based on 1990 emissions data, as EPA used 1990 as the baseline year for that listing. We describe above in Section II.A of this preamble the pollutants that formed the basis of the listings.

This rule applies to all existing and new industrial boilers, institutional boilers, and commercial boilers located at area sources. Boiler means an enclosed combustion device having the primary purpose of recovering thermal energy in the form of steam or hot water. The industrial boiler source category includes boilers used in manufacturing, processing, mining, refining, or any other industry. The commercial boiler source category includes boilers used in commercial establishments such as stores/malls, laundries, apartments, restaurants, and hotels/motels. The institutional boiler source category includes boilers used in medical centers (e.g., hospitals, clinics, nursing homes), educational and religious facilities (e.g., schools, universities, churches), and municipal buildings (e.g., courthouses, prisons).

C. What is the relationship between this rule and other related national emission standards?

This rule regulates industrial boilers and institutional/commercial boilers that are located at area sources of HAP. Today, in a parallel action, a NESHAP for industrial, commercial, and institutional boilers and process heaters located at major sources is being promulgated reflecting the application of MACT. The major source NESHAP regulates emissions of PM (as a surrogate for non-mercury metals), mercury, HCl (as a surrogate for acid gases), dioxins/furans, and CO (as a surrogate for non-dioxin organic HAP) from existing and new major source boilers.

This rule covers boilers located at area source facilities. In addition to the major source MACT for boilers being issued today, the Agency is also issuing emission standards today pursuant to CAA section 129 for commercial and industrial solid waste incineration units. In a parallel action, EPA is finalizing a solid waste definition rulemaking pursuant to subtitle D of RCRA. That action is relevant to this proceeding because if an industrial, commercial, or institutional boiler located at an area source combusts secondary materials that are "solid waste," as that term is defined by the Administrator under RCRA, those boilers would be subject to section 129 of the CAA, not section 112.

As background, in 2007, the United States Court of Appeals for the District of Columbia Circuit (DC Circuit) vacated the "CISWI Definitions Rule" (70 FR 55568, September 22, 2005), which amended the definitions of "commercial and industrial solid waste incinerator (CISWI)," "commercial or industrial waste," and "solid waste" in 40 CFR 60, subparts CCCC and DDDD, and which EPA issued pursuant to CAA section 129. The Court found that the definitions in that rule were inconsistent with the CAA. Specifically, the Court held that the term "solid waste incineration unit" in CAA section 129(g)(1) "unambiguously include[s] 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 at 1257–58.

Based on the information available to the Agency, we determined that the boilers that are subject to this area source rule combust predominantly coal, oil, or biomass. We have further determined that the boilers subject to this rule may combust non-hazardous secondary materials that do not meet the definition of "solid waste" pursuant to the rulemaking of subtitle D of RCRA. A boiler located at an area source burning any secondary materials considered "solid waste" would be considered a solid waste incineration unit subject to regulation under CAA section 129. In the final area source 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.

Some of the affected sources subject to this rule may also be subject to the NSPS for industrial, commercial, and institutional boilers (40 CFR part 60, subparts Db and Dc). EPA codified these NSPS in 1986, and revised portions of them in 1999 and 2006. The two NSPS regulate emissions of PM, SO_2, and NO_X from boilers constructed after June 19, 1984. Sources subject to the NSPS that are located at area source facilities are also subject to this rule because this rule regulates HAP. In developing this rule, we have streamlined the monitoring and recordkeeping requirements to avoid duplicating requirements in the NSPS.

D. How did we gather information for this rule?

We gathered information for this rule from states' boiler inspection lists, company Web sites, published literature, state permits, current state and federal regulations, and from an ICR conducted for the major source NESHAP. After proposal, we received additional emission test reports during the public comment period.

We developed an initial nationwide population of area source boilers based on boiler inspector data-bases from 13 states. The boiler inspector data-bases include steam boilers that are required to be inspected for safety or insurance purposes. We classified the area source boilers to NAICS codes based on the "name" of the facility at which the boiler was located. However, many of the boilers in the boiler inspector data-base could not be readily assigned to an NAICS code and, thus, we did not categorize them.

We reviewed state and other federal regulations that apply to the area sources in the source categories for information concerning existing HAP emission control approaches. For example, as noted above, the NSPS for small industrial, commercial, and institutional boilers in 40 CFR part 60, subpart Dc apply to boilers at some area sources. Similarly, permit requirements established by the Ohio, Illinois, Vermont, New Hampshire, and Maine air regulatory agencies apply to some area sources. We also reviewed standards for boilers at major sources that would be appropriate for and transferable to boilers at area sources. For example, we determined that management practices, such as, tune-ups and operator training applicable to major source boilers are also feasible for boilers at area sources.

E. How are the area source boiler HAP addressed by this rule?

As explained in Section II.A of this preamble, industrial coal combustion, industrial oil combustion, industrial wood combustion, commercial coal combustion, commercial oil combustion, and commercial wood combustion are listed under CAA section 112(c)(6) due to contributions of mercury and POM and these same categories are listed under CAA section 112(c)(3) for their contribution of mercury, arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, POM, ethylene dioxide, and PCB.

With respect to the CAA section 112(c)(3) pollutants, we used surrogates because, as explained in this section of the preamble, it was not practical to establish individual standards for each specific HAP. We grouped the CAA section 112(c)(3) pollutants, which formed the basis for the listing of these two source categories, into three common groupings: Mercury, non-mercury metallic HAP (arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel), and organic HAP (POM, ethylene dichloride, and PCB). In general, the pollutants within each group have similar characteristics and can be controlled with the same techniques.

For the non-mercury metallic HAP, we selected PM as a surrogate. The inherent variability and unpredictability of the non-mercury metal HAP compositions and amounts in fuel has a material effect on the composition and amount of non-mercury metal HAP in the emissions from the boiler. As a result, establishing individual numerical emissions limits for each non-mercury HAP metal species is difficult given the level of uncertainty about the individual non-mercury metal HAP compositions of the fuels that will be combusted. An emission characteristic common to all boilers is that the non-mercury metal HAP are a component of the PM contained in the fly ash emitted from the boiler. A sufficient correlation exists between PM and non-mercury metallic HAP to rely on PM as a surrogate for these HAP and for their control.[1] Therefore, the same control techniques that would be used to control the fly-ash PM will control non-mercury metallic HAP. Emissions limits established to achieve control of PM will also achieve control of non-mercury metallic HAP. Furthermore, establishing separate standards for each individual HAP would impose costly and significantly more complex compliance and monitoring requirements and achieve little, if any, HAP emissions reductions beyond what would be achieved using the surrogate pollutant approach.

For organic urban HAP, we selected CO as a surrogate for organic compounds, including POM, emitted from the various fuels burned in boilers. The presence of CO is an indicator of incomplete combustion. A high level of CO in emissions is a potential indication of elevated organic HAP emissions because organic HAP, like CO, are formed as a byproduct of combustion, and both would increase with an increase in the level of incomplete combustion. Monitoring equipment for CO is readily available, which is not the case for organic HAP. Also, it is significantly easier and less expensive to measure and monitor CO emissions than to measure and monitor emissions of each individual organic HAP. We considered other surrogates, such as total hydrocarbon (THC), but lacked data on emissions and permit limits for area source boilers. Therefore, using CO as a surrogate for organic urban HAP is a reasonable approach because minimizing CO emissions will result in minimizing organic urban HAP emissions.

Based on these considerations, we are promulgating GACT standards for PM (as a surrogate for the individual urban metal HAP) for coal, biomass, and oil-fired boilers and CO (as a surrogate pollutant for the individual urban organic HAP) for biomass-fired and oil-fired boilers. We are also establishing MACT standards for mercury and for POM (using CO as a surrogate pollutant) for coal-fired boilers. The MACT standard for POM from coal-fired boilers would also be GACT for urban organic HAP other than POM.

F. 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 AREA SOURCE RULE IN 2014

[Millions of 2008$][1]

	3% Discount rate	7% Discount rate
Final MACT/GACT Approach: Selected		
Total Monetized Benefits[2]	$210 to $520	$190 to $470
Total Social Costs[3]	$490	$490
Net Benefits	−$280 to $30	−$300 to −$20
Non-monetized Benefits;	1,100 tons of carbon monoxide 340 tons of HCl 8 tons of HF 90 pounds of mercury 320 tons of other metals < 1 gram of dioxins/furans (TEQ) Health effects from SO_2 exposure Ecosystem effects Visibility impairment	
Proposed MACT Approach: Alternative		
Total Monetized Benefits[2]	$200 to $490	$180 to $440
Total Social Costs[3]	$850	$850

[1] In *National Lime Ass'n* v. *EPA,* 233 F. 3d 625, 633 (DC Cir. 2000), the court upheld EPA's use of particulate matter as a surrogate for HAP metals.

SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE BOILER AREA SOURCE RULE IN 2014—Continued

[Millions of 2008$] [1]

	3% Discount rate	7% Discount rate
Net Benefits	−$650 to −$360	−$670 to −$410
Non-monetized Benefits	1,100 tons of carbon monoxide 340 tons of HCl 8 tons of HF 90 pounds of mercury 320 tons of other metals <1 gram 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 SO_2. 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 less than $1 million.

[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

A. Do these standards apply to my source?

This rule applies to you if you own or operate a boiler combusting solid fossil fuels, biomass, or liquid fuels located at an area source. The standards do not apply to boilers that are subject to another standard under 40 CFR part 63 or to a standard developed under CAA section 129.

This rule applies to you if you own or operate a boiler combusting natural gas, located at an area source, which switches to combusting solid fossil fuels, biomass, or liquid fuel after June 4, 2010.

B. What is the affected source?

This final rule affects industrial boilers, institutional boilers, and commercial boilers. The affected source is the collection of all existing boilers within a subcategory located at an area source facility or each new boiler located at an area source facility.

C. When must I comply with these standards?

The owner or operator of an existing source subject to a work practice or management practice standard of a tune-up is required to comply with this final rule no later than March 21, 2012. The owner or operator of an existing source subject to emission limits or an energy assessment requirement is required to comply with this final rule no later than March 21, 2014. The owner or operator of a new source is required to comply on May 20, 2011 or upon startup of the facility, whichever is later. Owners and operators subject to 40 part CFR 60, subpart CCCC or subpart DDDD who cease combusting solid waste must be in compliance with this subpart on the effective date that the unit ceased combusting solid waste, consistent with 40 CFR part 60, subpart CCCC or subpart DDDD.

D. What are the MACT and GACT standards?

Emission standards are in the form of numerical emission limits for new and existing area source boilers. The MACT emission limits for mercury and CO (as a surrogate for POM) are presented, along with the GACT emission limits for PM (as a surrogate for urban metals), in Table 1 of this preamble. The units are pounds of PM or mercury per million British thermal units (lb/MMBtu) and ppm for CO.

TABLE 1—EMISSION LIMITS FOR AREA SOURCE BOILERS

Subcategory	Heat input (MMBtu/h)	Pollutants	Emission limits
New coal-fired boiler	≥30	a. Particulate Matter	0.03 lb per MMBtu of heat input.
		b. Mercury	0.0000048 lb per MMBtu of heat input.
		c. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen.
	≥10 and <30	a. Particulate Matter	0.42 lb per MMBtu of heat input.
		b. Mercury	0.0000048 lb per MMBtu of heat input.
		c. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen.
New biomass-fired boiler	≥30	Particulate Matter	0.03 lb per MMBtu of heat input.
	≥10 and <30	Particulate Matter	0.07 lb per MMBtu of heat input.
New oil-fired boiler	≥30	Particulate Matter	0.03 lb per MMBtu of heat input.
	≥10 and <30	Particulate Matter	0.03 lb per MMBtu of heat input.
Existing coal-Fired boiler	≥10	a. Mercury	0.0000048 lb per MMBtu of heat input.

TABLE 1—EMISSION LIMITS FOR AREA SOURCE BOILERS—Continued

Subcategory	Heat input (MMBtu/h)	Pollutants	Emission limits
		b. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 7 percent oxygen.

The emission limits for PM apply only to new boilers. The emission limits for mercury and CO apply only to boilers in the coal subcategory; the emission limits for existing area source boilers in the coal subcategory are applicable only to area source boilers that have a designed heat input capacity of 10 million MMBtu/h or greater.

If your boiler burns any solid fossil fuel and no more than 15 percent biomass on a total fuel annual heat input basis, the boiler is in the coal subcategory. If your boiler burns at least 15 percent biomass on a total fuel annual heat input basis, the unit is in the biomass subcategory. If your boiler burns any liquid fuel and is not in either the coal or the biomass subcategory, the unit is in the oil subcategory, except if the unit burns oil only during periods of gas curtailment.

As allowed under CAA section 112(h), a work practice standard is being promulgated for new and existing coal-fired area source boilers with a designed heat input capacity of less than 10 MMBtu/h. The work practice standard for new and existing coal-fired area source boilers requires the implementation of a tune-up program. We are also requiring all biomass-fired and oil-fired area source boilers to implement a tune-up program as a management practice.

An additional standard is being promulgated for existing area source facilities having an affected boiler with a designed heat input capacity of 10 MMBtu/h or greater that requires the performance of an energy assessment, by qualified personnel, on the boiler and its energy use systems to identify cost-effective energy conservation measures.

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

The United States Court of Appeals for the District of Columbia Circuit vacated portions of two provisions in EPA's CAA section 112 regulations governing the emissions of HAP during periods of startup, shutdown, and malfunction (SSM). *Sierra Club* v. *EPA,* 551 F.3d 1019 (DC Cir. 2008), cert. denied, 130 S. Ct. 1735 (U.S. 2010). Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), that are part of a regulation, commonly referred to as the "General Provisions Rule" (40 CFR 63, subpart A), that EPA promulgated under CAA section 112 of the CAA. When incorporated into CAA section 112(d) regulations for specific source categories, these two provisions exempted sources from the requirement to comply with the otherwise applicable CAA section 112(d) emission standard during periods of SSM.

Consistent with *Sierra Club* v. *EPA,* EPA has established standards in this rule that apply at all times. EPA has attempted to ensure that we have not incorporated into the regulatory language any provisions that are inappropriate, unnecessary, or redundant in the absence of an SSM exemption.

In establishing the standards in this 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, including following the manufacturer's recommended procedures for minimizing startup and shutdown periods, to demonstrate compliance with the emission limits for all subcategories of new and existing area source boilers (that would otherwise be subject to numeric emission limits) during periods of startup and shutdown. As discussed in Section V.G of this preamble, we considered whether performance testing, and therefore, enforcement of numeric emission limits, would be practicable during periods of startup and shutdown. With regards to performance testing, 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. 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.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 63.2). EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times. In *Mossville Environmental Action Now* v. *EPA,* 370 F.3d 1232, 1242 (DC Cir. 2004), the 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 (DC Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.").

Further, it is reasonable to interpret CAA section 112(d) as not requiring EPA to account for malfunctions in setting emissions standards. For example, we note that CAA section 112 uses the concept of "best performing" sources in defining MACT, the level of stringency that major source standards must meet. Applying the concept of "best performing" to a source that is malfunctioning presents significant difficulties. The goal of best performing sources is to operate in such a way as to avoid malfunctions of their units. Similarly, although standards for area sources are generally not required to be set based on "best performers," we believe that what is "generally available" should not be based on periods in which there is a "failure to operate."

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 area source boilers. 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 (*see* 40 CFR 63.2 (definition of malfunction), EPA must 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." (*See* 40 CFR 63.2 (definition of malfunction).)

Finally, EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.,* State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (September 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (February 15, 1983)). EPA is therefore adding to this final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. (*See* 40 CFR 63.11226 (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 63.11226. (*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 reasonable preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *." The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 63.11205(a), and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *" and that "[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *." In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113 of the CAA (*see* also 40 CFR 22.77).

F. What are the initial compliance requirements?

For new and existing area source boilers with applicable emission limits, you must conduct initial performance tests to determine compliance with the PM, mercury, and CO emission limits. The performance tests to demonstrate compliance with the mercury emission limit can be either a stack test, which also requires a fuel analysis, or only a fuel analysis.

As part of the initial compliance demonstration, you must monitor specified operating parameters during the initial performance tests that demonstrate compliance with the PM, mercury, and CO emission limits for area source boilers. The test average establishes your site-specific operating levels.

For owners or operators of existing and new coal-fired area source boilers having a heat input capacity of less than 10 MMBtu/h and all existing and new biomass-fired and oil-fired area source boilers, you must submit to the delegated authority or EPA, as appropriate, documentation that a tune-up was conducted.

For owners or operators of existing area source facilities having a boiler with a heat input capacity of 10 MMBtu/h or greater and subject to this rule, you must submit to the delegated authority or EPA, as appropriate, documentation that the energy assessment was performed and the cost-effective energy conservation measures identified.

G. What are the continuous compliance requirements?

If you demonstrate initial compliance with the emission limits by performance (stack) tests, then you must conduct stack tests every 3 years. Furthermore, to demonstrate continuous compliance with the PM, CO, and mercury emission limits, you must monitor and comply with the applicable site-specific operating limits.

For area source boilers that must comply with the PM and mercury emission limits, you must continuously monitor opacity and maintain the opacity at or below 10 percent (daily block average) or:

1. If the boiler is controlled with a fabric filter, the fabric filter may be continuously operated such that the alarm on the bag leak detection system does not sound more than 5 percent of the operating time during any 6-month period.

2. If the boiler is controlled with an electrostatic precipitator (ESP), you must maintain the minimum voltage and secondary amperage (or total power input) of the ESP at or above the minimum operating limits established during the performance test.

3. If the boiler is controlled with a wet scrubber, you must monitor pressure drop and liquid flow rate of the scrubber and maintain the daily block averages at or above the minimum operating limits established during the performance test.

4. For boilers with sorbent or carbon injection systems which must comply with an applicable mercury emission limit, you must maintain the daily block averages at or above the minimum sorbent flow rate, as calculated according to 40 CFR 63.11221(a)(5).

If you elected to demonstrate initial compliance with the mercury emission limit by fuel analysis, as determined according to 40 CFR 63.11211(b), you must conduct a monthly fuel analysis and maintain the annual average at or below the limit indicated in Table 1 of this preamble.

For boilers that demonstrate compliance with the PM and mercury emission limits by performance (stack) tests, you must maintain monthly fuel records that demonstrate that you burned no new fuel type or new mixture (monthly average) as set during the performance test. If you plan to burn a new fuel type or new mixture that is different from what was burned during the initial performance test, then you must conduct a new performance test to demonstrate continuous compliance with the PM emission limit and mercury emission limit.

For boilers that must comply with the CO emission limits, you must continually monitor oxygen and maintain an oxygen concentration level, on a 30-day rolling average basis, at no less than 90 percent of the average oxygen concentration measured during the most recent performance test.

Biomass and oil-fired boilers must meet the management practice standards defined in Table 2 to 40 CFR part 63, subpart JJJJJJ.

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

All new and existing sources will be required to comply with some requirements of the General Provisions (40 CFR part 63, subpart A), which are identified in Table 6 to subpart JJJJJJ. The General Provisions include specific requirements for notifications, recordkeeping, and reporting. If performance tests are required under subpart JJJJJJ, then the notification and reporting requirements for performance tests in the General Provisions also apply.

Each owner or operator is required to submit a notification of compliance status report, as required by 40 CFR 63.9(h) of the General Provisions. Subpart JJJJJJ rule requires the owner or operator to include in the notification of compliance status report certifications of compliance with rule requirements.

If your unit is subject to an emission limit, then you must prepare, by March 1 of each year, an annual compliance certification report for the previous calendar year certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of this subpart.

This rule requires records to demonstrate compliance with each emission limit, work practice standard, and management practice. These recordkeeping requirements are specified directly in the General Provisions to 40 CFR part 63.

Records for applicable management practices must be maintained. Specifically, the owner or operator must keep records of the dates and the results of each boiler tune-up.

Records are required for either continuously monitored parameter data for a control device, if a device is used to control the emissions, or continuous opacity monitoring system (COMS) data.

Each owner and operator is 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, work/management practice, and operating limit (*i.e.*, deviations from this final rule);

(4) Monthly fuel use by each boiler including a description of the type(s) of fuel(s) burned, amount of each fuel type burned, and units of measure;

(5) A copy of the results of all performance tests, energy assessments, opacity observations, performance evaluations, or other compliance demonstrations conducted to demonstrate initial or continuous compliance with this final rule; and

(6) A copy of your site-specific monitoring plan developed for this final rule, if applicable.

Records must be retained for at least 5 years. In addition, monitoring plans, operating and maintenance plans, and other plans must be updated as necessary and kept for as long as they are still current.

I. Submission of Emissions Test Results to EPA

Compliance test data are necessary for many purposes including compliance determinations, development of emission factors, and determining annual emission rates. EPA has found it burdensome and time consuming to collect emission 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 bulky paper copies.

In this action, we are taking a step to improve data accessibility for stack tests (and in the future continuous monitoring data). Boiler area sources are required to submit to WebFIRE (an EPA electronic data base) an electronic copy of stack test reports as well as process data. Data entry requires only access to the Internet and is expected to be completed by the stack testing company as part of the work that it is contracted to perform.

Please note that the requirement to submit source test data electronically to EPA does not require any additional performance testing. In addition, when a facility submits performance test data to WebFIRE, there are no additional requirements for data compilation; instead, we believe industry will greatly benefit from improved emissions factors, fewer information requests, and better regulation development as discussed below. Because the information that is being reported is already required in the existing test methods and is necessary to evaluate the conformance to the test methods, facilities are already collecting and compiling these data. The Electronic Reporting Tool (ERT) was developed with input from stack testing companies, who already collect and compile performance test data electronically. One major advantage of submitting source test data through ERT is that it provides a standardized method to compile and store all the documentation required by subpart JJJJJJ. Another important benefit of submitting these data to EPA at the time the source test is conducted is that these data should reduce the effort involved in data collection activities in the future for these source categories. 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). Finally, another benefit of submitting these data to WebFIRE electronically is that these data will greatly improve the overall quality of the existing and new emissions factors by supplementing the pool of emissions test data upon which emissions factors are 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 out-dated or not representative of a particular source category. Receiving recent performance test results would ensure that emissions factors are updated and more accurate. In summary, receiving these 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.

As mentioned earlier, the electronic data-base that will be used is EPA's WebFIRE, which is a Web site accessible through EPA's TTN (technology transfer network). The WebFIRE Web site was constructed to store emissions test data for use in developing emission factors. A description of the WebFIRE data-base can be found at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main*. The ERT will be able to transmit the electronic report through EPA's Central Data Exchange (CDX) network for storage in the WebFIRE data base. Although ERT is not the only electronic interface that can be used to submit source test data to the CDX for entry into WebFIRE, it makes submittal of data very straightforward and easy. A description of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/ert_tool.html*.

The ERT can be used to document the conduct of stack tests for various pollutants including PM, mercury, dioxin/furan, and HCl. Presently, the ERT does not accept opacity data or CEMS data.

IV. Summary of Significant Changes Following Proposal

A. Changes to Subcategories

We have redefined the coal, biomass and oil subcategories for area source boilers to clarify the fuel-type inputs that would define each subcategory. The proposed rule defined the biomass subcategory to include any boiler that burns any amount of biomass, either alone or in combination with a liquid or gaseous fuel. This definition excluded boilers that burned biomass with coal; boilers burning greater than 10 percent coal on an annual fuel heat input basis were defined under the coal-fired subcategory. This final rule defines the biomass subcategory to include any boiler that burns at least 15 percent of biomass on an annual heat input basis.

Similarly, the proposed rule defined the oil subcategory to include any boiler that burns any liquid fuel either alone or in combination with gaseous fuels, and excluded boilers that burned solid fuels. We have revised this final rule to define the oil subcategory to include any boiler that burns any liquid fuel and is not in either the biomass or coal subcategory.

The coal subcategory in this final rule has been revised to include any boiler combusting any solid fossil fuels and no more than 15 percent biomass. This final rule defines solid fossil fuels to include, but not limited to, coal, petroleum coke, and tire derived fuel (TDF).

B. Change From MACT to GACT for Biomass and Oil Subcategories

The proposed rule set MACT-based emission limits for CO (as a surrogate pollutant for the individual urban organic HAP) from new and existing biomass-fired and oil-fired boilers. For POM from area source boilers classified as biomass-fired or oil-fired, as well as with respect to other urban HAP besides POM, we have revised this final rule standards to reflect GACT for these two area source subcategories (*see* Section V.D of this preamble). We are implementing management practice standards, as allowed by CAA section 112(d)(5), for control of POM from new and existing area source boilers in the biomass and oil subcategories. The management practice standard requires the implementation of a tune-up program.

C. MACT Floor UPL Methodology/Emission Limits

At proposal, we used a 99 percent UPL calculation to determine variability. In this final rule, we have determined that 99 percent UPL is appropriate for fuel based HAP and a 99.9 percent UPL is appropriate for combustion dependent HAP (i.e., CO). We have modified our assumptions when results of the skewness and kurtosis tests result in a tie between normal and log-normal calculations, or when there is not enough data to complete the skewness and kurtosis tests, to choose the log-normal results. We have also revised the UPL calculation to convert log-normally distributed data to an arithmetic mean instead of a geometric mean. Further, for fuel based HAP (*i.e.,* mercury), we have implemented an additional fuel variability factor in the emission limits.

D. Clarification of Energy Assessment Requirements

The proposed rule required owners and operators of existing area source boilers with a heat input capacity of 10 MMBtu/h and greater to have an energy assessment performed by a qualified professional. The proposed rule defined an energy assessment as an "in-depth assessment of a facility to identify immediate and long-term opportunities to save energy, focusing on the steam and process heating systems which involves a thorough examination of potential savings from energy efficiency improvements, waste minimization and pollution prevention, and productivity improvement." The requirements for the energy assessment, defined in Table 3 of the proposed rule, included visually inspecting the boiler system, establishing operating characteristics and energy system specifications, identifying the boiler's major energy consuming systems, listing major energy conservation measures, and a comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, and the benefits associated with such.

This final rule requires an energy assessment for all existing boilers with a heat input capacity of 10 MMBtu/h or greater, and clarifies the definition of energy assessment with respect to the requirements of Table 3 of this final rule. The revised definition provides a maximum duration for performing the energy assessment and defines the evaluation requirements for each boiler system and energy use system. These requirements are based on the total annual heat input of the affected boilers.

This final rule requires an energy assessment for facilities with affected boilers using less than 0.3 trillion Btu per year 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 the boilers 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 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 using greater than 1 TBtu/year heat input, the energy assessment must comprise the boiler system and any energy use system accounting for at least 20 percent of the energy output to identify energy savings opportunities.

We have also added a definition for "energy use systems" to clarify the components, in addition to the boiler system, which must be considered during the energy assessment.

E. Revised Subcategory Limits

The proposed rule set emission limits for PM (as a surrogate for the individual urban metal HAP) for all new area source boilers and CO (as a surrogate pollutant for the individual urban organic HAP) for all new area source boilers and for existing area source boilers with a heat input capacity of 10 MMBtu/h or greater. The proposed rule also set emission limits for mercury from new and existing coal-fired boilers.

In this final rule, the emission limits for mercury and CO have been revised for existing coal-fired boilers with a heat input capacity greater than 10 MMBtu/h. The MACT emission limits for the coal subcategory have been revised based on the revised MACT floor approach (see Section V of this preamble). Existing boilers in the biomass and oil subcategories are not required to meet emission limits for CO in this final rule; these units must meet the management practice standards of implementing a boiler tune-up program.

In this final rule, the PM emission limits for new area source boilers have been revised based on the size category. For new boilers in the coal, biomass, and oil subcategories with a heat input capacity less than 10 MMBtu/h, GACT is a management practice of a tune-up. For new boilers between 10 and 30 MMBtu/h heat input, the PM limit has been revised to reflect the performance of GACT, which is a multiclone. The emission limits for mercury and CO have been revised for new coal-fired boilers with a heat input capacity greater than 10 MMBtu/h. New boilers in the biomass and oil subcategories are not required to meet emission limits for CO; these units must meet the management practice standards of a tune-up.

Table 2 of this preamble summarizes the revised emission limits for each pollutant for each subcategory.

TABLE 2—REVISED EMISSION LIMITS FOR SUBPART JJJJJJ

Subcategory	Heat input (MMBtu/hr)	Pollutant	Proposed emission limit	Final emission limit
New coal-fired boiler	≥30	Particulate Matter	0.03 lb per MMBtu of heat input	0.03 lb per MMBtu of heat input
		Mercury	0.000003 lb per MMBtu of heat input.	0.0000048 lb per MMBtu of heat input
		Carbon Monoxide	310 ppm by volume on a dry basis corrected to 7 percent oxygen	400 ppm by volume on a dry basis corrected to 3 percent oxygen
	≥10 and <30	Particulate Matter	0.03 lb per MMBtu of heat input	0.42 lb per MMBtu of heat input
		Mercury	0.000003 lb per MMBtu of heat input.	0.0000048 lb per MMBtu of heat input
		Carbon Monoxide	310 ppm by volume on a dry basis corrected to 7 percent oxygen	400 ppm by volume on a dry basis corrected to 3 percent oxygen
New biomass-fired boiler	≥30	Particulate Matter	0.03 lb per MMBtu of heat input	0.03 lb per MMBtu of heat input
		Carbon Monoxide	100 ppm by volume on a dry basis corrected to 7 percent oxygen.	Management Practice Standards (see Table 2 to subpart JJJJJJ)
	≥10 and <30	Particulate Matter	0.03 lb per MMBtu of heat input	0.07 lb per MMBtu of heat input
		Carbon Monoxide	100 ppm by volume on a dry basis corrected to 7 percent oxygen.	Management Practice Standards (see Table 2 to subpart JJJJJJ)
New oil-fired boiler	≥30	Particulate Matter	0.03 lb per MMBtu of heat input	0.03 lb per MMBtu of heat input
		Carbon Monoxide	1 ppm by volume on a dry basis corrected to 3 percent oxygen.	Management Practice Standards (see Table 2 to subpart JJJJJJ)
	≥10 and <30	Particulate Matter	0.03 lb per MMBtu of heat input	0.03 lb per MMBtu of heat input
		Carbon Monoxide	1 ppm by volume on a dry basis corrected to 3 percent oxygen.	Management Practice Standards (see Table 2 to subpart JJJJJJ)
Existing coal-Fired boiler	≥10	Mercury	0.000003 lb per MMBtu of heat input.	0.0000048 lb per MMBtu of heat input
		Carbon Monoxide	310 ppm by volume on a dry basis corrected to 7 percent oxygen	400 ppm by volume on a dry basis corrected to 3 percent oxygen
Existing biomass-fired boiler.		Carbon Monoxide	160 ppm by volume on a dry basis corrected to 7 percent oxygen	Management Practice Standards (see Table 2 to subpart JJJJJJ)
Existing coal-fired boiler		Carbon Monoxide	2 ppm by volume on a dry basis corrected to 3 percent oxygen	Management Practice Standards (see Table 2 to subpart JJJJJJ)

F. Demonstrating Compliance

We have revised the compliance dates for existing affected sources according to the applicable provisions for each affected source (e.g., work practice standards, emission limits, management practice standards, and/or an energy assessment). Under the proposed rule, owners and operators of existing sources would have had to comply with this final rule within 3 years following March 21, 2011. This final rule requires that if you own or operate an existing source subject to a work practice or management practice standard of a tune-up, you must comply with this final rule no later than March 21, 2012. If you own or operate an existing source subject to an emission limit or an energy assessment requirement, you must comply with this final rule no later than March 21, 2014. Under the proposed rule, the owner or operator of a new source would have been required to comply on the date of publication of the final rule or upon startup of the facility, which ever was later. Because this rule is subject to the Congressional Review Act, the owner or operator of a new source is required to comply on May 20, 2011 or upon startup of the facility, whichever is later.

Additionally, we have clarified the compliance requirements for commercial and industrial solid waste incineration units subject to 40 CFR part 60, subpart CCCC or subpart DDDD that cease combusting solid waste and become subject to Subpart JJJJJJ. Owners and operators of commercial and industrial solid waste incineration units must be in compliance with this subpart on the effective date of the waste to fuel switch (at least 12 months from the date that the owner or operator ceased combusting solid waste), if the effective date is after the applicable compliance dates discussed above.

We have also revised the proposed continuous compliance requirements to be consistent with changes to the emission limits in this final rule, and are no longer requiring CO CEMS for biomass, oil, and coal-fired units. For new and existing coal units with a heat input capacity greater than 10 MMBtu/h, we are requiring stack testing every 3 years to demonstrate compliance with the CO emission limits. Because boilers in the biomass and oil subcategories are only required to meet the management practice standards in Table 2 of 40 CFR part 63, subpart JJJJJJ, no testing for CO emissions is required for these units.

G. Affirmative Defense

We have added provisions to this final rule to include an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. Consistent with *Sierra Club* v. *EPA,* EPA has established standards in this rule that apply at all times. However, in response to an action to enforce the standards set forth in 40 CFR 63.11201, you may assert an affirmative defense for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 63.2. (*See* 40 CFR 63.11226 (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). The included provisions specify the elements that are necessary to establish an affirmative defense for periods of malfunction, including evidence and notification requirements that must be prepared by the source.

H. Technical/Editorial Corrections

In this final action, we are making a number of technical corrections and clarifications to subpart JJJJJJ. 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.

We made several changes to the initial compliance demonstration requirements. We revised 40 CFR 63.11211(a) to clarify that sources using a second fuel only for start up, shutdown, and/or transient flame stability are still considered to be sources using a single fuel. We deleted 40 CFR 63.11210(b) to remove the requirement that boilers with a heat input capacity above 100 MMBtu/h are required to demonstrate compliance by conducting a performance evaluation of their CO CEMS.

We made a change to the monitoring requirements in 40 CFR 63.11225 (40 CFR 63.11224 in the proposed rule). We deleted paragraph (e) to remove the requirement that boilers having a heat input capacity of 100 MMBtu/h and subject to a CO limit install a CO CEMS.

In response to comments asking for clarification, we have added definitions to 40 CFR 63.11237 for "Annual heat input basis," "Energy use system," "Hot water heater," "Minimum scrubber pressure drop," "Minimum voltage or amperage," "Qualified energy assessor," and "Solid fossil fuel." 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.

Several of the definitions in 40 CFR 64.11237 were revised to clarify the types of equipment to which different standards apply. For example, 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 supplemental burners. 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.

V. Significant Area Source Public Comments and Rationale for Changes to Proposed Rule

This section contains a brief summary of major comments and responses. EPA received many comments on this subpart covering numerous topics. EPA's responses to all comments, including those below, can be found in the comment response document for Area Source Industrial, Commercial, and Institutional Boilers in the docket.

A. Legal and Applicability Issues

Section 112(c)(6) of the CAA

Comment: Some commenters stated that EPA misinterpreted the statute in using MACT instead of GACT for area sources. These commenters argued that the statute allows for setting a standard under CAA section 112(d)(2) that can be satisfied using the alternative GACT procedure specified in CAA section 112(d)(5) to meet the 112(c)(6) requirements.

Response: We disagree with the comment that the CAA gives EPA discretion to promulgate GACT standards pursuant to section 112(d)(5) for area source categories required to be regulated under section 112(c)(6). Section 112(c)(6) of the CAA explicitly requires that "sources accounting for not less than 90 per centum of the aggregate emissions of each [pollutant specified in this provision] are subject to standards under subsection 112(d)(2) or (d)(4) * * *." (Emphasis added). The plain language of section 112(c)(6) requires that the Agency set standards under section 112(d)(2) or (d)(4). There is no ambiguity in this language and thus the legislative history cited by the commenter is irrelevant. As such, the Agency is appropriately setting standards for the sources at issue pursuant to section 112(d)(2).

The commenter argues that section 112(d)(5) trumps the very specific language in section 112(c)(6). We disagree. Congress unambiguously required the Agency to set standards for these persistent, bioaccumulative HAP under section 112(d)(2) or (d)(4). Had Congress wanted us to permit EPA to issue GACT standards for the 112(c)(6) HAP, it would have said that EPA could issue standards under section 112(d), as it did in section 112(k)(3)(B) of the Act, noting that area sources shall be subject to standards issued pursuant to "subsection (d) of this section." Congress could not have been more precise in section 112(c)(6), and we reject the commenter's interpretation.

EPA has consistently maintained that standards under section 112(d)(2) or (d)(4) are required for the pollutants listed in section 112(c)(6). In this case, we are setting a section 112(d)(2) MACT standard for mercury and CO (as a surrogate for POM) for coal-fired area source boilers, which are the 112(c)(6) pollutants that form the basis for the listing of the source category at issue here.

Comment: One commenter argued that EPA did not provide justification for its decision that mercury and POM must be regulated pursuant to CAA section 112(c)(6) at area source boilers to satisfy the requirements that 90 percent of nationwide emissions of these pollutants must be reduced. The commenter further stated that the proposed rule and supporting documentation provide no rational basis or adequate factual justification for the need to regulate area source POM or mercury emissions to satisfy CAA section 112(c)(6). Specifically, the commenter stated that neither the proposed rule nor the MACT floor memo provide data that support the proposed determination that 90.3 percent of the 1990 emissions inventory for mercury is already subject to regulation. In contrast, another commenter said that, once a category is listed under CAA section 112(c)(6), the only procedure available to EPA for refraining from promulgating a MACT-based standard for the category is to remove the category from the CAA section 112(c) list through the use of CAA section 112(c)(9), regardless of whether the category is needed to meet the 90 percent requirement in CAA section 112(c)(6).

Response: The statute does not limit EPA's discretion as to how it fulfills its obligations under CAA section 112(c)(6). To the extent that the commenters seek to challenge whether EPA has selected appropriate categories to meet its obligations under CAA section 112(c)(6) or whether EPA has met the requirement in CAA section 112(c)(6) to regulate categories emitting at least 90 percent of the specified pollutants (in this case, mercury and POM), such challenges should not be reviewed in the context of a review of an individual NESHAP. Rather, if review is appropriate, it should be in the context of an EPA finding that it has fulfilled its obligations under CAA section 112(c)(6), and an accounting by the agency of how it reached the 90 percent threshold for each pollutant. Nevertheless, the docket for this rulemaking contains a spreadsheet that demonstrates our belief that we have met the 90 percent requirement for POM and for mercury with this final rule.

While we are promulgating GACT-based provisions at this time for mercury and POM from biomass-fired and oil-fired area source boilers, note that we have not removed or "delisted" oil-fired and biomass-fired area source boilers by this action. We are not promulgating MACT-based regulations at this time because they are unnecessary to meet the requirements of CAA section 112(c)(6).

Comment: Comments received suggested EOM was not appropriate for representing POM emissions. The commenters noted a drawback to using EOM as a surrogate for POM is the limited amount of data available to quantify emissions and the few EOM inventories or emission factors in existence. Commenters also stated that EOM includes other extractible organics in addition to the PAHs. The commenters suggest that the reasonable assumption is that any observed health effects come from the PAH fraction and since EOM includes compounds other than PAH, it should not be used as a surrogate for POM.

Response: This issue primarily affects whether biomass-fired and oil-fired boilers are needed to meet the CAA section 112(c)(6) requirements. EPA has considered commenter input and revised the final rule based on our re-examination of our section 112(c)(6) baseline inventory for POM. As we noted in the proposed rule, we reexamine the inventory associated with the original listing as we learn more about the source category in the rule development process (75 FR 31904). Based on a re-examination of the emission inventory in light of comments, we have determined that we only need to address the coal-fired portion of the area source segments of these categories under CAA section 112(c)(6) in order to meet the 90 percent threshold requirement of that provision for both mercury and POM.

As discussed in the preamble to the June 2010 proposed rule (75 FR 31896), we have determined that we must regulate mercury and POM from coal-fired area source boilers in order to meet the requirements in CAA section 112(c)(6), and we are establishing MACT-based limits for mercury and POM (using CO as a surrogate) for this subcategory. We are implementing work practice standards, as allowed by CAA section 112(h), for control of mercury and POM from new and existing area source boilers in the coal subcategory with a designed heat input capacity less than 10 MMBtu/h.

In the CAA section 112(c)(6) source listing, we used three indicators (7–PAH, 16–PAH, and extractable organic matter (EOM)) to represent POM emissions and compiled three separate baseline inventories for POM, one for each indicators. In light of the comment described above regarding EOM, we re-examined our three section 112(c)(6) baseline inventories for POM. For the reason stated below, we have decided to use only the baseline inventory for 16–PAH in determining the 90 percent threshold under section 112(c)(6).

We agree with the commenters who have identified data gaps in our knowledge of what source categories are emitting EOM. While we have data on 16–PAH emissions for 94 categories, we only have available data on EOM emissions for 18 source categories. The lack of available data on EOM emission creates a distorted picture of the relative contributions of source categories for which there are available EOM data. The lack of source categories making up the total EOM inventory makes the relative contribution of the few categories that do have data unrealistically inflated.[2] We therefore cannot say with confidence that by using the baseline inventory for EOM we are capturing 90 percent of the baseline POM emissions, as required by section 112(c)(6). Similarly, we have data on 7–PAH for 32 categories, considerably fewer than the 94 categories for which we have 16–PAH data. Because the 16–PAH inventory allows for the most accurate representation of the universe of categories that emit POM, we have decided to use that baseline inventory for determining the 90 percent threshold for POM under section 112(c)(6). Based on the baseline inventory for 16–PAH, regulating POM emissions from area source biomass and oil boilers are not needed to meet the CAA section 112(c)(6) obligations. Thus, POM emissions from area source boilers in the biomass and oil subcategories can be regulated under GACT, instead of MACT.

With respect to mercury and POM from area source boilers classified as biomass-fired or oil-fired, as well as with respect to other urban HAP besides POM, we have revised the final rule standards to reflect GACT for these two area source subcategories (*see* Section IV.B of this preamble). We are implementing management practice standards, as allowed by CAA section 112(d)(5), for control of POM from new and existing area source boilers in the biomass and oil subcategories. The management practice standard for new and existing area source boilers requires the implementation of a tune-up program.

As stated previously in the preamble to the June 2010 proposed rule, we determined that the control technologies currently used by facilities in the source category to reduce non-mercury metallic HAP and PM (multiclone, fabric filters, and ESP) are generally available and cost effective for new area source boilers. Additionally, these controls are commonly required by state and other federal regulations that apply to the area source boilers in the source category. Therefore, we are establishing numeric emission limits representing GACT for all new area source boilers with a heat

[2] When justifying its use in the 1998 inventory, we said that EPA would undertake an effort to develop a robust inventory for EOM sources to feed into the CAA section 112(c)(6) inventory. Had more data been gathered, perhaps EOM would have proved to be a more useful indicator of POM. However, the anticipated inventory was not developed.

input capacity greater than 10 MMBtu/h (using PM as a surrogate).

Emission Standards for HAP Other Than Mercury

Comment: One commenter stated that CAA section 112(c)(6) provides that EPA must "list categories and subcategories of sources assuring that sources accounting for not less than 90 percent of each [enumerated] pollutant are subject to standards under subsection (d)(2) or (d)(4) of this section." The commenter also stated that the DC Circuit has held repeatedly that when EPA sets standards for a category or subcategory of sources under section 112(d)(2), EPA has a statutory duty to set emission standards for each HAP that the sources in that category or subcategory emit. The commenter concluded that when EPA sets standards for area source boilers under section 112(d)(2), as section 112(c)(6) requires it to do, EPA must set section 112(d)(2) emission standards for all the HAP that area source boilers emit.

The commenter said that EPA appears to believe that because area source boilers are needed only to reach the section 112(c)(6) requirement of 90 percent for mercury and POM and not for the other pollutants enumerated in section 112(c)(6), EPA's only obligation under section 112(c)(6) is to set section 112(d)(2) standards for mercury and POM. The commenter said that section 112(c)(6) expressly requires EPA to issue section 112(d)(2) standards for the "sources" in the categories listed under section 112(c)(6), not some subset of the pollutants that those sources emit, and that section 112(d)(2) standards must include emission standards for each HAP that a source category emits. The commenter continued by stating that nothing in the CAA exempts EPA from this requirement. The commenter concluded that, had Congress wished to give EPA discretion to set standards for only some of the pollutants emitted by a category listed under section 112(c)(6), it would have done so expressly.

Response: EPA disagrees with the comment that, even though EPA lists a category under section 112(c)(6) due to the emissions of one or more HAP specified in that section, EPA must issue emission standards for all HAP (including HAP not listed in section 112(c)(6)) that sources in that category emit. The commenter cited in support the opinion by the United States Court of Appeals for the DC Circuit in *National Lime Ass'n* v. *EPA,* 233 F.3d 625, 633–634 (DC Cir. 2000)). The part of the *National Lime* opinion referenced in the comment dealt with EPA's failure to set emission standards for certain HAP emitted by major sources of cement manufacturing because the Agency found no sources using control technologies for those HAP. In rejecting EPA's argument, the court stated that EPA has "a statutory obligation to set emission standards for each listed HAP." *Id.* at 634. The Court noted the list of HAP in section 112(b) and stated that section 112(d)(1) requires that EPA "promulgate regulations establishing emission standards for each category or subcategory of *major sources* * * * of hazardous air pollutants listed for regulation * * *" *Id.* (Emphasis added). For the reasons stated below, we do not believe that today's final rule is controlled by or otherwise conflicts with the *National Lime* decision.

National Lime did not involve section 112(c)(6). That provision is ambiguous as to whether standards for listed source categories must address all HAP or only the section 112(c)(6) HAP for which the source category was listed. Section 112(c)(6) requires that "sources accounting for not less than 90 per centum of the aggregate emissions of each such [specific] pollutant are subject to standards under subsection (d)(2) or (d)(4)." This language can reasonably be read to mean standards for the section 112(c)(6) HAP or standards for all HAP emitted by the source. Under either reading, the source would be subject to a section 112(d)(2) or (d)(4) standard.

The commenter insists that once a section 112(d)(2) standard comes into play, all HAP must be controlled (per *National Lime*). But this result is not compelled by the pertinent provision, section 112(c)(6). That provision is obviously intended to ensure controls for specific persistent, bioaccumulative HAP, and this purpose is served by a reading which compels regulation under section 112(d)(2) only of the HAP for which a source category is listed under section 112(c)(6), rather than for all HAP.

The facts here support the reasonableness of EPA's approach. Area source boilers are included in source categories listed under section 112(c)(6) for regulation under section 112(d)(2) solely due to its mercury and POM emissions. There is special statutory sensitivity to regulation of area source categories in section 112. For example, an area source category may be listed for regulation under section 112 if EPA makes an adverse effects finding pursuant to Section 112(c)(3) or if EPA determines that the area source category is needed to meet its section 112(c)(3) obligations to regulate urban HAP or its section 112(c)(6) obligations to regulate certain persistent bioaccumulative HAP. Moreover, to the extent EPA lists an area source category pursuant to section 112(c)(3) (whether that finding is based on adverse effects to human health or the environment or a finding that the source is needed to meet the 90 percent requirement in section 112(c)(3)), the statute gives EPA discretion to set GACT standards for such sources (42 U.S.C. 7412(d)(5)).

EPA does not interpret section 112(c)(6) to create a means of automatically compelling regulation of all HAP emitted by area sources unrelated to the core object of section 112(c)(6), which is control of the specific persistent, bioaccumulative HAP, and thereby bypassing these otherwise applicable preconditions to setting section 112(d) standards for area sources. Nor does *National Lime* address the issue, since the case dealt exclusively with major sources (233 F. 3d at 633). Consequently, EPA disagrees with the comment that it is compelled to promulgate section 112(d)(2) MACT standards for all HAP emitted by area source boilers.

Beyond-the-Floor Option

We are promulgating the proposed standard requiring the performance of an energy assessment for existing area source facilities having an affected boiler with a designed heat input capacity of 10 MMBtu/h or greater. This final rule requires the performance of an energy assessment, by qualified personnel, on the boiler and its energy use systems to identify cost-effective energy conservation measures. As discussed in the June 2010 proposed rule, an energy assessment provides valuable information on improving energy efficiency. Owners and operators are encouraged, but not required, to use the results of the energy assessment to increase the energy-efficiency and cost-efficiency of their boiler system.

In the proposed rule, the energy assessment requirement was a beyond-the-floor option for the MACT-based mercury and CO emission standards because additional emission reductions would be realized as the results of these energy assessments, if implemented. In this final rule, the energy assessment requirement is both a beyond-the-floor control for the MACT-based standards for the coal subcategory and a GACT for the biomass and oil subcategory because energy assessments are generally available and have already been performed at numerous facilities.

The principal 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).

With respect to the first argument, we have carefully limited the requirement to perform an energy assessment to specific portions of the source that directly affect emissions from the affected boiler, as indicated by the revised definition of an energy assessment in section 63.11237 of subpart JJJJJJ. The emissions that are being controlled come from the affected source. For coal-fired units, the process changes resulting from a change in an energy using system will reduce the volume of emissions at the affected source. For biomass-fired and oil-fired area sources, better management practices at energy using systems will reduce the emissions of HAP from the affected source by reducing fuel consumption and the HAP released through combustion of fuel. In either case, the requirement controls the emissions of the affected source.

With respect to the second argument, the energy assessment will generate emission reductions through the reduction in fuel use beyond those 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.[3] Therefore, the requirement to perform an energy assessment can both be enforced and will result in emission reductions.

Section 112(h) of the CAA

Comment: Commenters stated that setting work practice standards in lieu of emission standards for area source boilers with a heat input capacity less than 10 MMBtu/h is unlawful and arbitrary. Commenters cited EPA's determination with respect to the technical and economic limitations on the enforcement of emission standards for boilers with heat input capacity less than 10 MMBtu/h, and stated that these limitations do not satisfy CAA section 112(h) conditions for setting work practice standards in lieu of emission standards. Some commenters argued that the technical limitations of measuring PM using Method 5, as discussed in the preamble to the proposed June 2010 rule, do not apply to mercury and CO. Other commenters remarked that the absence of sampling ports and stacks at area source boilers does not provide a basis for a technical or economic limitation, stating that sources are able to work around this issue. Multiple commenters said that the lack of measuring ports (which can affect retrofitting new boiler installations into existing buildings), other design requirements for efficient exhaust from smaller boilers, and the inapplicability of approved test methods would make measurement technically and economically impractical for both existing and new sources. Commenters specifically cited CAA section 112(h)(1) and (2), which allows the agency to prescribe work practice standards only if it is "not feasible to prescribe or enforce an emission standard * * * due to technological or economic limitations."

Response: EPA disagrees with commenters. As discussed in the preamble to the June 2010 proposed rule, CAA section 112(h) authorizes the Administrator to promulgate "a design, equipment, work practice, or operational standard, or combination thereof," consistent with the provisions of CAA sections 112(d) or (f), in those cases where, in the judgment of the Administrator, it is not feasible to prescribe or enforce an emission standard. CAA section 112(h)(2)(B) further defines the term "not feasible" to mean when "the application of measurement technology to a particular class of sources is not practicable due to technological and economic limitations." We have elected to implement work practice standards for coal-fired boilers with a heat input capacity of less than 10 MMBtu/h because we have determined that the standard reference methods for measuring emissions of mercury, CO (as a surrogate for POM), and PM (as a surrogate for urban non-mercury metals) are not applicable for sampling small diameter (less than 12 inches) stacks. Furthermore, through the comment process, we have learned that common, very small boilers (less than 5 MMBtu/h) typically exhaust through vents and not stacks, and that the installation of ports into small diameter vents for smaller boilers would likely interfere with the functionality of exhaust systems for new and existing boilers. Because many existing area source boilers with a capacity below 10 MMBtu/h generally have stacks with diameters less than 12 inches, and because many area source boilers do not currently have sampling ports or a platform for accessing the exhaust stack, we have determined that the testing and monitoring costs that area source boiler facilities would incur to demonstrate compliance with the proposed emission limits would present an excessive burden for smaller sources. Thus, we are establishing work practice standards to limit the emissions of mercury and CO (as a surrogate for POM) for existing and new coal-fired area source boilers having a heat input capacity of less than 10 MMBTU/h.

De minimis Levels

Comment: Several commenters stated that EPA should establish a *de minimis* heat input level (less than 1 MMBtu/h heat input capacity) below which area sources are not subject to regulation or only subject to work practice standards. These commenters referenced water heaters and small comfort heating units that are not used in industrial, commercial, or institutional processes but instead used to provide hot water for personal use or seasonal comfort heating. Other commenters noted that State rules that require work practice requirements for boilers all have a lower limit on applicability of typically 1 to 5 MMBtu/h; these commenters stated that EPA has provided no basis for applying work practice standards to boilers of this size.

Response: EPA must establish standards for each category or subcategory of major sources and area sources of HAP listed pursuant to CAA section 112(c). EPA may distinguish among classes, types, and size in establishing such standards but the standards established must be applicable to new and existing sources of HAP within the category. However, we agree with the commenters that the categories of boiler covered by this rule are industrial boilers, commercial

[3] Case studies and success stories highlighting energy savings achieved by companies that have participated in *Save Energy Now* energy assessments and used Industrial Technologies Program software tools to improve energy efficiency can be found at *http://www1.eere.energy.gov/industry/saveenergynow/case_studies.html* and at the Department of Energy's Energy Assessment Centers Database *http://iac.rutgers.edu/database.*

boilers, and institutional boilers. In the proposed rule, we did not list hot water heaters as exempted as we did in the proposed Boiler MACT for major sources. As stated in the preamble to the proposed Boiler MACT, hot water heaters meet the definition of a boiler but are more appropriately described as residential-type boilers, not industrial, commercial, or institutional boilers because their output is intended for personal use rather than for use in an industrial, commercial, or institutional process. The primary reason for exempting hot water heaters in the Boiler MACT was that hot water heaters are not part of the listed source category. Because hot water heaters generally use natural gas and gas-fired boilers were not part of the area source category, we did not include a similar exemption in the proposed rule. To be consistent with the Boiler MACT, we have included in this final rule a similar exemption and definition for hot water heaters.

B. CO Limits

Comment: Multiple commenters argued that EPA's determination of using CO as a surrogate for POM is inappropriate. Several of these commenters reiterated that there is no reliable correlation between CO and POM. Some commenters stated that CO is not an appropriate surrogate for POM or organic HAP at lower CO emission levels. For instance, one commenter stated that while there is a linear correlation between decreasing CO and decreasing HAP at higher levels, once CO values fall under 100 ppm, further reduction of CO does not provide any substantial correlating reduction of HAP. Other commenters stated that CO is an inadequate surrogate for POM because there is no POM invariably present in CO; likewise, commenters stated that because CO and POM have different mechanisms of formation and reduction, CO cannot be considered as a reliable surrogate.

Several commenters suggested total hydrocarbon (THC) as a better surrogate, stating that THC levels are often more stable and less reactive to load swings than CO. Commenters noted that THC has been used as a surrogate for organic HAP emissions in other regulatory efforts, including the hazardous waste incinerator MACT.

Response: EPA acknowledges commenters' concerns. Based on new data received during the public comment period, we have re-examined our analysis and revised the final standards for CO. As previously discussed, this final rule only establishes CO emission limits for coal-fired boilers pursuant to CAA section 112(c)(6). We are implementing management practice standards, as allowed by CAA section 112(d)(5), for control of CO from new and existing area source boilers in the biomass and oil subcategories. Additionally, for the coal subcategory, we have revised the final CO emission limits to ensure a more accurate correlation between POM and CO levels. EPA is aware of one European study [4] that finds the correlation between CO and POM (or organic HAP, in general) is weaker at lower CO concentrations (less than 100 ppmv) but we did not have the opportunity to examine the data relied on by the study and no data supporting this supposition were submitted as part of the public comments. We have revised the final standards (400 ppm) based on 99.9 percent UPL as discussed in Section IV.C of this preamble. EPA believes that CO is a reliable surrogate for POM at this emission level. EPA considered using THC as a surrogate for POM, however, we did not have available THC data for area sources.

Comment: Several commenters expressed concern with respect to the proposed CO limits. Some commenters stated that the proposed CO limits are unachievable for some units, including liquid-fired boilers. Commenters further stated that meeting the CO limits would be more burdensome for area sources than major sources. Specifically, many commenters argued that the CO limits are unfeasible from a measurement, operability, and cost standpoint, particularly when considered simultaneously with other limits (NO_X, VOC). Some commenters expressed concern that prioritizing CO reduction may promote boiler inefficiency and result in higher emissions of NO_X.

Other commenters suggested that the CO emission limits should be determined using long-term CEMS data to account for natural variability in CO emissions. Commenters also offered alternatives for control of POM. One commenter suggested that EPA consider cleaner fuels or end of stack technologies for control, such as fabric filters and scrubbers that capture POM and POM-precursors.

Response: As discussed above, this final rule establishes MACT-based emission limits for CO only for new and existing coal-fired boilers. In this final rule, area source boilers in the biomass and oil-fired subcategories are not required to meet CO emission limits; these boilers are instead required to meet the management practice standard which consists of a tune-up. The MACT-based CO emission limits are still required for coal-fired area source boilers in order to meet our obligation under CAA section 112(c)(6). Based on the available CO data and the revised UPL calculation methodology, the final CO emission limits for coal-fired area source boilers are higher than the proposed limits which should provide more assurance that the limit can be achieved at all times. EPA notes that the available dataset did not include sufficient long-term CEMS data for area sources to be used to set a limit. Therefore, we have established the CO standards based on the data provided using the revised UPL methodology to account for variability over the operating cycle of typical industrial, commercial, and institutional boilers. We also considered other appropriate control options for sources in each subcategory, including switching to clean fuels and end of stack technologies. We considered whether fuel switching could be technically achieved by boilers in the subcategory considering the existing design of boilers and the availability of various types of fuel. We determined that fuel switching was not an appropriate control technology based on the overall effect of fuel switching on HAP emissions and the technical and design considerations discussed previously in the preamble to the proposed June 2010 rule (75 FR 31896). This determination is discussed in the memorandum "Development of Fuel Switching Costs and Emission Reductions for Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Area Source" located in the docket. Additionally, EPA did not identify add-on control technologies available for control of CO in use at area source boilers.

C. MACT Floor Analysis

Pollutant-by-Pollutant Approach

Comment: Several commenters argued that the pollutant-by-pollutant approach used by EPA is not appropriate. Commenters rejected the pollutant-by-pollutant approach on the basis that both PM and CO emission limits are not achievable even for the best performing sources. These commenters argued that because the proposed area source MACT standards rely on a different set of best performing sources for each separate HAP standard, no single source is in the

[4] European Wood-Heating Technology Survey: An Overview of Combustion Principles and the Energy and Emissions Performance Characteristics of Commercially Available Systems in Austria, Germany, Denmark, Norway, and Sweden; Final Report; Prepared for the New York State Energy Research and Development Authority; NYSERDA Report 10–01; April 2010.

population of units for both the PM and CO emission limits, and therefore, the approach does not reflect the performance of the best performing boilers. Rather, commenters asserted that the proposed limits were unrealistic, unnecessarily stringent, and unachievable. Commenters further stated that the provisions of CAA sections 112(d)(1), (2), and (3) of the CAA require that standards must be based on actual sources, and cannot be the product of pollutant-by-pollutant "cherry-picking." Commenters stated that EPA does not have the authority to "distinguish" units and sources by individual pollutant. Other commenters stated that EPA must set limits for each HAP that the sources in the subcategory emit, and not solely mercury or POM. These commenters stated that to ignore the emitted HAP violates the CAA and the court order.

Response: EPA is mindful that MACT floors must reflect achieved performance. EPA is also mindful that that costs cannot be considered by EPA in ascertaining the level of the MACT floor. *See,* e.g., *Brick MACT,* 479 F. 3d at 880–81, 882–83; *NRDC* v. *EPA,* 489 F. 3d 1364, 1376 (DC Cir. 2007) ("Plywood MACT"); *see* also *Cement Kiln Recycling Coalition* v. *EPA,* 255 F. 3d 855, 861–62 (DC Cir. 2001) ("achievability" requirement of CAA section 112(d)(2) cannot override the requirement that floors be calculated on the basis of what best performers actually achieved).

EPA has carefully developed data for each standard, assessing both technological controls and HAP inputs in doing so. The MACT floor variability methodology is discussed in a later response.

Among all boilers at area sources, only new and existing coal-fired ones will need to meet MACT-based limits. Nevertheless, it is true that at least some coal-fired area source boilers will need to install controls to meet these standards, and that these controls have significant costs. This is part of the expected MACT process where, by definition, the averaged performance of the very best performers sets the minimum level of the standard. The Agency believes that it has followed the statute and applicable case law in developing its floor methodology. Although industry commenters maintain these sources cannot meet the standards, which are predicated on their own performance without adding controls, this contention lacks a basis in the record. For mercury, 6 of the 7 boilers for which EPA has emissions data are meeting the MACT floor standards for mercury. For CO, 13 of the 16 boilers in the MACT pool meet the promulgated standard. In those instances where commenters provided actual data on these plants' performance, EPA took the information into account in developing the final standards. Indeed, EPA adjusted all of the standards based on actual data presented. We have emissions data on a limited number of area source units. The available information does indicate that at least one unit meets both the final PM and CO emission limits.

Dataset for the MACT Floor Analysis

Comment: Commenters stated numerous objections to the dataset used for the MACT floor analysis. Some commenters stated that it is inappropriate to apply limits from data submitted as part of the major source industrial boiler MACT ICR to area sources. Commenters objected to EPA's assertion that boilers at area sources are similar in size and operation to major source boilers; one commenter noted that EPA did not use test data from area source facilities to set major source floors.

Other commenters stated that the emission limits are significantly flawed because they are based on inadequate data and not representative of the units in the source category. These commenters stated that the data collected is insufficient because it represents the performance of less than 1 percent of almost 183,000 existing area source boilers, particularly given that EPA based the analysis on the top 12 percent of units for which data were available. Commenters further stated that there was insufficient data available to establish appropriate boiler-type subcategories.

Some commenters expressed that EPA must include emissions data collected by state and local permitting authorities in establishing the MACT floor; these commenters stated that these data are more objective than the newer industry testing and are also necessary to fill in "gaps" in the existing data. Other commenters requested that certain data should be excluded from the MACT floor analysis. For instance, some commenters stated that non-detect data should be excluded or that the analysis should be adjusted to account for the capabilities of the test methods. These commenters stated that the non-detect data results in an unreasonably low MACT floor; some commenters stated that the proposed limits are in some cases below the detection capability of the required test method. Commenters also stated that EPA has not justified using three times the detection level in its analysis. These commenters stated that this method biases the results towards higher HAP emissions, results in a hypothetical standard that is unrealistic and not determined as required by statute.

Response: EPA acknowledges commenters' concerns. As mentioned elsewhere in this preamble, EPA is required to establish MACT floor levels using existing emissions information. For all data sets, the final emission limits are based on the available data and EPA's assessment of variability. Since proposal we have received updated data on certain boilers and used that data to revise our emission estimates from the best performing sources. We re-evaluated the information available for the area source category and revised the proposed MACT-based CO emission limits such that they only apply to boilers in the coal subcategory. As discussed above, based on information received during the public comment period, we determined that regulating POM emissions from area source biomass and oil boilers is not needed to meet our CAA section 112(c)(6) obligations; we only need to regulate coal-fired area source boilers under section 112(d)2) to meet the 90 percent requirement set forth in CAA section 112(c)(6) for POM. The emissions limits for CO for coal-fired boilers were based on the available information from the ICR and state operating permits, as well as that received in comments.

EPA disagrees with commenters who stated that we excluded emissions data collected by state and local permitting authorities in establishing the MACT floor. The available state permits obtained for coal-fired area source boilers limiting CO emissions were for 11 units located in Ohio (3 units), and Illinois (8 units). We also obtained CO emission data from five coal-fired area source boilers as part of the information collection effort for the major source NESHAP. Even though the latter data were gathered in the course of collecting data on major sources, the emission data on these five boilers is from emission sources in the area source coal-fired boiler subcategory.

With respect to non-detect data, EPA considered and accounted for non-detect data when conducting the MACT analysis for mercury for existing and new coal-fired boilers in this final rule. EPA developed a methodology to account for the imprecision introduced by incorporating non-detect data into the MACT floor calculation. At very low emission levels where emissions tests result in non-detect values, the inherent imprecision in the pollutant measurement method has a large influence on the reliability of the data underlying the MACT floor emission limit. Because of sample and emission 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 confidence level that a value, measured at the detection level is greater than zero, is about 99 percent. The expected measurement imprecision for an emissions value occurring at or near the method detection level is about 40 to 50 percent. Pollutant measurement imprecision decreases to a consistent level of 10 to 15 percent for values measured at a level about three times the method detection level.[5]

One approach that we believe can be applied to account for measurement variability in this situation starts with defining a method detection level that is representative of the data used in the data pool. The first step in this approach would be to identify the highest test-specific method detection level reported in a data set that is also equal to or less than the average emission calculated for the data set. This approach has the advantage of relying on the data collected to develop the MACT floor emission 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 is to determine the value equal to three times the representative method detection level and compare it to the calculated MACT floor emission limit. If three times the representative method detection level were less than the calculated MACT floor emission limit, we would conclude that measurement variability is adequately addressed, and we would not adjust the calculated MACT floor emission limit. If, on the other hand, the value equal to three times the representative method detection level were greater than the calculated MACT floor emission limit, we would conclude that the calculated MACT floor emission limit does not account entirely for measurement variability. Therefore, we revised the approach we used for the proposal and, for the final rule, we used the value equal to 3 times the method detection level in place of the calculated MACT floor emission limit to ensure that the MACT floor emission limit for mercury accounts for measurement variability and imprecision.

Variability

Comment: Numerous commenters stated that the floor methodology used by EPA is unlawful. Some commenters criticized EPA's application of the UPL to all the test results for all sources in the top twelve percent. These commenters stated that while EPA can consider variability in estimating an individual source's performance over time, it cannot account for differences in performance between sources. Specifically, these commenters stated that EPA may only account for differences in performance between sources except as CAA section 112(d)(3) provides, by averaging the emission levels achieved by the sources in the top 12 percent. Commenters stated that the UPL is not equivalent to the "average" emission level. For instance, some commenters stated that the methodology for the mercury and CO emission limits for new coal fired units does not reflect the emission levels achieved by the single best performing source; these commenters stated that the proposed method results in higher emission levels for new sources than the average level of the best 12 percent.

Commenters further stated that EPA erred by relying on the 99 percent UPL only to reflect variability. Some commenters stated that EPA must collect and consider data on additional variability, such as that related to variable fuel quality or longer term variability, to supplement its analysis. These commenters stated that the short-term test data are not representative of long-term operation of a unit nor are they likely to reflect the "worst reasonably foreseeable circumstances" a unit may experience. Other commenters stated that EPA should use the upper tolerance limit (UTL) in lieu of the UPL; these commenters claimed that the UTL is more appropriate for situations where the available data does not represent the entire population.

Response: EPA disagrees with commenters and believes that the final emission limits appropriately account for variability. The Court has recognized that EPA may consider variability in estimating the degree of emission reduction achieved by the best-performing sources and in setting MACT floors that the best performing sources can expect to meet "every day and under all operating conditions". *See Mossville Environmental Action Now* v. *EPA,* 370 F.3d 1232, 1241–42 (DC Cir 2004). Furthermore, CAA section 112(d)(3) includes a provision stating that the MACT floor for existing sources 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)." We see no statutory prohibition in considering inter-source variability of the best performing sources (which is all our floor calculation does, by considering the pooled variability of the best performing sources). Section 112(d)(3) of the CAA does not specify any single method of ascertaining an average. Considering the average variability among the group of best performing sources is well within the language of the provision (and was upheld in *Chemical Manufacturers Association* v. *EPA; see* 870 F. 2d at 228). The commenters' argument that "average" can only mean average of emission levels achieved in performance tests of an individual unit is inconsistent with the holding in *Mossville,* 370 F. 3d at 1242, that EPA must account for variability in developing MACT floors and that individual performance tests do not by themselves account for such variability. Therefore, we believe that it is reasonable and necessary to account for inter-source variability of the best performing sources by taking the pooled average of the best performing sources' variability. This is an aspect of identifying the average performance of those sources.

Furthermore, EPA is confident that the UPL is an appropriate statistical tool to use in determining variability when there is a limited sampling of the source category. EPA has considered comments regarding suggested alternatives to the UPL statistic, such as the upper tolerance limit (UTL). Whereas a confidence interval covers a population parameter with a stated confidence, that is, a certain proportion of the time, a tolerance interval covers a fixed proportion of the population with a stated confidence. That is, 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 this definition, 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 floor 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 area source boiler

[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.

floor data are small, the 99th percentile is underestimated. Therefore, EPA notes that 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. On the other hand, 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. 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. Given the above considerations, EPA notes that only the UPL adequately gets at the notion of average emissions for a small sample size.

EPA 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 is lognormally distributed, so EPA has modified its assumptions when the results of the skewness and kurtosis tests result in a tie, or when there is not enough data to complete the skewness and kurtosis tests. 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 [6]". Given data availability, EPA selected the Bhaumik and Gibbons 2004 approach which addresses commenters concerns with the proposed computations.

Additionally, EPA has determined that 99 percent UPL is appropriate for fuel based HAP, 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 (75 FR 54975). Further, as commenters have noted elsewhere, the sample sizes were limited and EPA determined that a level of 99 percent is a good compromise and represents emission levels that are protective of human health and the environment. Given that the subcategories had limited data to establish the floor calculations, EPA determined it was inappropriate to use a confidence level lower than 99 percent. Further, for fuel based HAP mercury, EPA has implemented an additional fuel variability analysis. Additionally, there are well established control measures currently used on units in the source category (fabric filters for PM and mercury) that serve to mitigate, to some degree, the variability in emissions that can be expected. Given these additional considerations 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. For CO, EPA considered both quantitative and qualitative comments received during the public comment period 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.

Finally, EPA notes that where appropriate, we have accounted for variable fuel quality. EPA first took fuel into consideration, among other boiler design factors when it 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. As noted in the preamble to the June 2010 proposed rule, EPA attempted to assess the impact of fuel variability for development of the mercury standard. However, no fuel analysis data from boilers in the top 12 percent were available for assessing the impact of fuel variability on mercury emissions. EPA realizes that mercury is a fuel dependent HAP, and that the amount of mercury emitted from the boiler depends on the amount of mercury contained in the fuel. For this final rule, we have implemented a fuel variability factor into the mercury emission limit by determining a factor relating the highest mercury content to the average mercury content in coal that may be used at sources comprising the best 12 percent of sources. We also note that fuel usage can be reduced by improving the combustion efficiency of the boiler. Therefore, in the development of the final standards, we are establishing requirements for larger existing boilers (greater than 10 MMBtu/h heat input capacity) to conduct an energy assessment, and smaller boilers (both existing and new boilers with a heat input capacity less than 10 MMBtu/h) to meet a work practice or management practice requirements of a tune-up, in order to improve combustion efficiency.

D. Beyond the Floor Analysis

Comment: Several commenters objected to EPA's beyond-the-floor determination for new area source boilers. Many of these commenters stated that the beyond the floor approach must consider fuel switching as an option. Other commenters objected to EPA's beyond-the-floor determination for existing boilers, specifically stating that EPA should require existing facilities to either comply with emission limits for larger units, or require fuel switching to the cleanest fuel in their class (fuel type). Commenters noted that while EPA identified substantial emissions reductions for mercury and POM from switching coal-fired boilers to natural gas, EPA failed to rationalize why fuel-switching is not a technically feasible or economically achievable option. Commenters debated EPA's stated concerns regarding fuel availability and curtailment, arguing that there is sufficient capacity to meet the expected increased demand for natural gas. Furthermore, these commenters stated that the potential increases in metallic HAP emissions from fuel-switching were minor and should be considered in light of overall reductions for POM.

Response: EPA has considered this comment and concluded that fuel switching is not an appropriate option for the beyond the floor level of control. EPA originally considered whether fuel switching would be an appropriate control option for sources in each subcategory under the proposed rule, including the feasibility of fuel switching to other fuels used in the subcategory and to fuels from other subcategories. This consideration included determining whether switching fuels would achieve lower HAP emissions. We also gave consideration to whether fuel switching could be technically achieved by boilers in the subcategory considering the existing design of boilers and the availability of various types of fuel. After considering these factors, we determined that fuel switching was not an appropriate control technology for purposes of determining the MACT floor level or beyond the floor level of control for any subcategory. This decision is based on the overall effect of

[6] Bhaumik, D. K. and R. D. Gibbons. 2004. An Upper Prediction Limit for the Arithmetic Mean of a Lognormal Random Variable. May 1, 2004. Technometrics 46(2): 239–248. doi:10.1198/004017004000000284

fuel switching on HAP emissions, technical and design considerations discussed previously in the preamble to the proposed June 2010 rule (75 FR 31896), and concerns about fuel availability. This determination is discussed in the memorandum "Development of Fuel Switching Costs and Emission Reductions for Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Area Source" located in the docket.

Energy Assessments

Comment: Several commenters disagreed with EPA's determination to require energy assessments as a beyond the floor option. Commenters specifically stated that EPA cannot require an energy assessment because an assessment is not an emission standard and there is no proven relationship between HAP emissions and the assessment. Other commenters argued that the proposed requirements for an energy assessment were not stringent enough; these commenters stated that an energy assessment cannot impose standards more stringent than the MACT floor. For instance, one commenter argued that if EPA did not require implementation of the energy assessment findings, no reductions in fuel use or HAP would result. The commenter further asserted that even an implemented energy assessment would not reduce HAP emissions consistent with the requirements of CAA section 112(d)(2). One commenter specifically stated that by only considering energy audits, EPA did not consider the full range of potential emission measures.

Other commenters argued that EPA does not have the authority to require an energy assessment, and that the proposed requirements were "too broad" or "too intrusive." Commenters were concerned that the energy assessment would include not only the affected source, but also the entire facility, which EPA does not have the authority to regulate.

Response: EPA disagrees with commenters that state that EPA does not have the authority to require an energy assessment. An energy assessment is an appropriate beyond-the-floor control technology because it is one of the measures identified in CAA section 112(d)(2). CAA section 112(d)(2) states that "Emission standards promulgated * * * and applicable to new or existing sources * * * is achievable * * * through application of measures, processes, methods, systems or techniques including, but not limited to measures which—

(A) Reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications, * * *

(D) Are design, equipment, work practice, or operational standards (including requirements for operator training or certification) as provided in subsection (h), or

(E) Are a combination of the above."

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

It is not EPA's intent to require an energy assessment for the entire facility; the energy assessment is only applied to existing boilers and their energy use systems located at area sources. EPA acknowledges that the proposed definition for "energy assessment" is unclear, and we have revised this final rule to clarify the definition with respect to the requirements of Table 3 of subpart JJJJJJ (*see* 40 CFR 63.11237). In order to account for variability among boiler systems and energy use systems and to ensure that affected sources can adequately comply with the requirements, we have distinguished the requirements for the energy assessment based on the heat input use of the affected source. We have also added a definition for "energy use systems" to clarify the components for each boiler system and energy use 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. These revisions clarify that an energy assessment is only required for those portions of the facility using the energy generated from the affected boiler system.

Additionally, a facility may elect, but is not required, to implement the cost-effective energy conservation measures identified in the energy assessment. Because we lack information on whether implementation of the conservation measures will prove cost-effective or economically feasible for facilities, we are allowing the owner or operator to determine the implementation of energy conservation measures identified in the energy assessment. EPA notes that the cost of an energy assessment is minimal, in most cases, compared to the cost for testing and monitoring to demonstrate compliance with an emission limit. Furthermore, the costs of any energy conservation improvement for the owner or operator will be offset, at least in part, by the cost savings in lower fuel costs. Therefore, after considering the structure of the requirement, the incentives it presents, and the likely behavior of sources, it is our judgment that sources will find it cost-effective to implement the conservation measures identified in the energy assessment, and we have elected to promulgate requirements for an energy assessment for all existing boilers with a heat input capacity greater than 10 MMBtu/h as a beyond the floor option or GACT.

EPA disagrees with commenters that state that the option for an energy assessment included in the June 2010 proposed rule is not stringent enough. An energy assessment refers to a process which involves a thorough examination of potential savings from energy efficiency improvements, pollution prevention, and productivity improvement. It leads to the reduction of pollutants through process changes and other efficiency modifications. Improving energy efficiency reduces negative impacts on the environment as well as operating and maintenance costs; improvements in energy efficiency result in decreased fuel use which results in a corresponding decrease in emissions (both HAP and non-HAP) from the boiler. The revised definitions of "energy assessment" and "energy use systems," as discussed above, have been expanded to include the specific components that must be considered for an energy assessment. These changes elucidate the in-depth nature of the energy assessment, which requires identifying all energy conservation measures appropriate for a facility given its operating parameters.

EPA proposed the energy assessment as a beyond the floor option for existing area source boilers having a heat input capacity of greater than 10 MMBtu/h, rather than focusing on smaller boilers. We also examined other emission measures currently in place. EPA did not have sufficient information to determine if requiring an energy assessment for area boilers with a heat input capacity of less than 10 MMBtu/h is economically feasible. For boilers with a heat input capacity less than 10 MMBtu/h, the data that we have suggests that area source boilers typically conduct boiler tune-ups. We also examined work practices listed in state regulations for area source boilers with a heat input capacity less than 10 MMBtu/h. These regulations included tune-ups (10 states), operator training (one state), periodic inspections (two states), and operation in accordance with manufacturer specifications (one state).

When energy assessments have been undertaken in the past, they typically result in 10 to 15 percent reduction in fuel use, according to the Department of Energy who has conducted energy assessment at selected manufacturing facilities.[7] While the efficiency gains may be somewhat less when the assessment is mandated for a source rather than voluntary, the absence of a requirement to implement the particular findings of the assessment should still result in measures being implemented that are cost-effective for the source and in emission reductions over and above what is otherwise required by MACT and other GACT measures. Therefore, we elected to promulgate requirements for an energy assessment for all existing boilers with a heat input capacity greater than 10 MMBtu/h, and require area source boilers in the biomass and oil subcategories with a heat input capacity of greater than 10 MMBtu/h to meet the management practice standard of a tune-up. These requirements represent the generally available and cost-effective pollution reduction measures that are already required or in place.

E. GACT Standards

Comment: Commenters stated that the GACT standards should consist of work practice standards, rather than numeric emission limits. One commenter specifically stated that in order to reduce the burden on small facilities operating boilers, EPA should establish work practice standards for CO instead of emission limits, referencing requirements from the state of New Jersey. Other commenters stated that the emission limits and testing procedures proposed for new boilers impose onerous capital and annual costs on potential project owners, which typically include schools, small businesses, hospitals, and other institutions in rural areas. Some commenters stated that the CO emission limits were not achievable for small boilers over a range of operating periods, and that EPA should consider work practice standards in order to account for load variability.

Response: CAA section 112(d)(5) allows the Administrator, with respect to area sources, to promulgate standards which provide for the use of generally available control technologies or management practices to reduce emissions of HAP. Therefore, with respect to mercury and POM from area source boilers classified as biomass-fired or oil-fired, as well as with respect to other urban HAP besides POM, we have developed standards that reflect GACT for these two area source categories.

While the June 2010 proposed rule (75 FR 31896) set numeric MACT standards for CO (as a surrogate pollutant for the individual urban organic HAP) and mercury, and numeric GACT emission limits for PM (as a surrogate for the individual urban metal HAP), EPA has revised the standards for area source boilers classified in the biomass and oil subcategories. Rather than require a numeric MACT emission limit for POM, new and existing area source boilers in the biomass or oil subcategories must meet the requirements of GACT, which are management practice standards as described in Table 2 of 40 CFR part 63, subpart JJJJJJ.

However, for the purposes of regulating PM from new area source boilers, EPA has determined that the GACT standards should consist of numeric emission limits. PM is used as a surrogate for urban metals, which we are required to regulate pursuant to CAA section 112(c)(6). The data that we have available suggests that the control technologies currently used by facilities in the source category for reduction of non-mercury metallic HAP and PM are multiclones, which are generally used at area sources using solid fuel. We previously determined during the development of the June 2010 proposed rule that these controls are generally available and cost effective for new area source boilers. Additionally, we noted that new area source boilers with heat input capacity of 30 MMBtu/h or greater are subject to the NSPS for boilers (either subpart Db or Dc of 40 CFR part 60), which regulate emissions of PM and require performance testing. Furthermore, new coal-fired area source boilers with heat input capacity of 10 MMBtu/h or greater will likely require a PM control device to comply with the proposed mercury MACT standard and required performance testing. Therefore, a numerical limit for PM consistent with the devices required to meet mercury MACT should be generally achievable.

EPA has also revised the PM emission limits for area source boilers with a heat input capacity between 10 and 30 MMBtu/h; these limits have been revised to reflect the performance of GACT, which are multiclones. The PM GACT limits were calculated as the average of the data from units using GACT technology. EPA has determined that the promulgated numeric emission limits for PM are appropriate GACT standards for new area source boilers with a heat input capacity greater than 10 MMBtu/h. For new boilers with a heat input capacity less than 10 MMBtu/h, GACT is a management practice of a tune-up because, as previously discussed, there are technical and economic limitations of conducting PM testing on boilers with small diameter stacks.

Tune-Ups

Comment: Several commenters expressed concern regarding proposed work practice standards for existing area source boilers, including the requirement of a tune-up for control of POM and mercury. Commenters stated that tune-ups aimed at reducing CO may increase NO_X emissions, reduce combustion efficiency, and/or increase fuel use. Commenters noted that many typical tune-up requirements, including states' requirements, are aimed at minimization of NO_X and not CO. These commenters stated that the proposed tune-up requirements could violate the state tune-up requirements due to increases of NO_X. Multiple commenters requested that EPA specify that tune-ups consider optimizing efficiency and limiting increases of NO_X, and not only require minimizing CO.

Other commenters requested that EPA allow the use of portable instruments to measure CO for the tune-up requirements. Several commenters requested that EPA clarify that, for the tune-up procedures, gases do not have to be measured using EPA Reference Methods. These commenters indicated that requiring EPA Methods would increase the cost burden for small facilities.

Response: EPA disagrees with commenters and is requiring tune-ups as a work practice standard for coal-fired area source boilers with a heat input capacity less than 10 MMBtu/h and as a management practice standard for all biomass-fired and oil-fired area source boilers. EPA acknowledges that that a tune-up designed to specifically decrease CO emissions from an area source boiler would potentially increase emissions of NO_X. However, it was not EPA's intent to require that area source

[7] Case studies and success stories highlighting energy savings achieved by companies that have participated in energy assessments can be found at *http://www1.eere.energy.gov/industry/saveenergynow/case_studies.html* and at the Department of Energy's Energy Assessment Centers Database *http://iac.rutgers.edu/database.*

boilers be specifically tuned for the reduction of CO emissions, but rather to require good combustion practices (GCP) by ensuring that area source boilers are tuned to manufacturer's specifications. As discussed in the preamble to the June 2010 proposed rule, boilers may be, at best, 85 percent efficient, and untuned boilers may have combustion efficiencies of 60 percent or lower. Furthermore, as the combustion efficiency decreases, fuel usage increases to maintain energy output resulting in increased emissions. A tune-up performed to the manufacturer's specifications would ensure the highest energy efficiency and reduce fuel usage, which will ultimately reduce HAP emissions. As commenters noted, the tune-up requirements specified by area source boiler manufacturers are generally aimed at reducing NO_X and would not increase emissions of NO_X. The tune-up provisions incorporated in this final rule for area source boilers require that the owner or operator measure the concentration in the effluent stream of CO in ppm, by volume, dry basis (ppmvd), before and after adjustments are made to the boiler. EPA does not specify the instrument that must be used for measuring these concentrations, and allows owners and operators to choose the method of measurement. Therefore, EPA agrees with commenters that portable instruments are permissible for this purpose.

F. Subcategories

Comment: Several commenters raised concerns regarding the subcategories defined by EPA in the development of the proposed rule. Multiple commenters argued that the proposed subcategories are unlawful and arbitrary because they are not based on different classes, types, or sizes. At least one commenter specifically stated that the proposed subcategorization defied the explicit recommendation of the Small Entity Representatives (SERs) to the Small Business Advocacy Review (SBAR) Panel, which recommended that "EPA should subcategorize based on fuel type, boiler type, duty cycle, and location." Many of these commenters suggested subcategories based on limited use, type of biomass (wood, bark, agricultural residue, moisture level) and/or coal (bituminous, anthracite), boiler design (stoker, fluidized bed, or suspension), heat input capacity smaller than 1 MMBtu/h, and combustion of secondary materials. Other commenters recommended that the same subcategories applied to major sources should be used for area sources.

Response: EPA disagrees with commenters. Section 112(d)(1) of the CAA states "the Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory" in establishing emission standards. Thus, we have discretion in determining appropriate subcategories based on classes, types, and sizes of sources. We used this discretion in developing subcategories for the boiler area source category. Through subcategorization, we are able to define subsets of similar emission sources within a source category if differences in emissions characteristics, technical feasibility of applying emission control techniques, or opportunities for pollution prevention exist within the source category. The design, operating, and emissions information that EPA reviewed during the area source rulemaking indicates the need to subcategorize based on boiler design which is based on the fuel type. EPA continues to believe that this subcategorization is appropriate. As noted in the preamble to the June 2010 proposed rule, boiler systems are designed for specific fuel types (e.g., coal, biomass, oil or a mixture/combination) and will encounter problems if a fuel or mixture with characteristics other than those originally specified is fired. EPA has noted that emissions from boilers burning coal, biomass, and oil will also differ, and that HAP formation, including emissions of metals and mercury, is dependent upon the composition of the fuel. Organic HAP, on the other hand, are formed from incomplete combustion, which are a function of time, turbulence, and temperature, and are influenced by the design of the boiler and dependent in part on the type of fuel being burned. Because these different types of boilers have different emission characteristics which may influence the feasibility and effectiveness of emission control, we believe that subcategorizing them by fuel type is appropriate.

Additionally, EPA notes that we lack sufficient emissions data for area source boilers to develop limits for additional subcategories. We have elected to establish different subcategories for the major and area source rulemakings, as major source boilers have a different scale of operation and often different combustor designs. There is also more detailed emissions data available for the major source category, which favors the development of more specific subcategories. Because we lack the same level of detail for the area source category, EPA has determined that it would be inappropriate to establish the same subcategories for major and area source boilers.

We believe that area source boilers are generally designed to burn a standard fuel type and less capable of switching fuel type as some major source boilers. However, as was done for the major source NESHAP, we have redefined how to determine the appropriate subcategory. Instead of considering whether the boiler 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 boiler.ies are determine.

In addition, as discussed in the comments below, we have established a small units subcategory for each type of fuel (area source boilers with a heat input capacity of less than 10 MMBtu/h), and see no further need for smaller subcategories. We have also adjusted the definition for each fuel subcategory to account for the combustion of secondary materials. The definitions have been clarified to specify that the fuel subcategories are based on the fuel that the boiler is designed to combust, rather than the actual fuel that the boiler is combusting.

Finally, as discussed earlier in this section, we have revised the MACT and GACT limits for the coal, oil, and biomass subcategories in this final rule. Existing oil and biomass-fired boilers are no longer required to meet emission limits, and are only required to meet management practice standards under this final rule. Furthermore, coal-fired boilers with a heat input capacity of less than 10 MMBtu/h are only required to meet work practice standards. While more stringent limits under this final rule may have required subcategories based on the size of the unit, EPA has determined that the subcategories chosen are reasonable based on the applicable requirements of this final rule.

Combustion of Secondary Fuels

Comment: Multiple commenters sought clarity for the combustion of secondary materials and/or alternative fuels within the proposed subcategories for area source boilers. Several of these commenters requested clarification of the defined fuels for the biomass, coal, and oil-fired subcategories, as well as additional clarification regarding gas-fired boilers. Some commenters stated that EPA's determination that the boilers subject to this rule do not combust any non-hazardous secondary materials is erroneous, and that to not consider standards for units burning secondary materials would be unlawful.

Many commenters recommended that EPA classify boilers based on predominant use of a particular fuel; several commenters recommended redefining the subcategories to allow minimal burning of other fuels or for further clarification. For instance, some commenters expressed concern regarding “combination boilers” (boilers that co-fire coal in an amount greater than 10 percent heat input basis with at least 10 percent biomass), which do not cleanly fit into either the coal-fired boiler subcategory or the biomass-fired boiler subcategory. Other commenters argued that the definition of gas-fired boilers should allow for units burning less than 10 percent liquid fuels. Many of the commenters suggested alternative definitions for the proposed subcategories or provided alternative thresholds.

Alternatively, there were some commenters who expressed concern regarding the use of alternative fuels. Commenters specifically stated that allowing 10 percent alternative fuel use, or use of multiple alternatives from year to year, would create significant enforcement issues for states without detailed requirements for tracking, recordkeeping, and reporting.

Response: EPA has considered these comments and revised the subcategories based on a revised MACT floor approach. As discussed in Section IV.A of this preamble, we have redefined the coal, biomass and oil subcategories for area source boilers to clarify the fuel inputs that define each subcategory. While the subcategories under the proposed rule accounted for secondary materials such as biomass, liquid or gaseous fuels combusted in combination with traditional fuels, we wished to clarify each subcategory in order to account for the combustion of an array of secondary fuels. Area source boilers combusting coal, biomass or oil may also combust secondary materials as part of their fuel mix. It was not our intent to exclude boilers combusting these non-hazardous secondary materials that do not meet the definition of “solid waste” from the coal, biomass or oil-fired subcategories. Therefore, we have revised the definition for each subcategory to account for the combustion of these non-hazardous secondary materials.

For instance, the proposed rule limited the coal subcategory to boilers combusting coal or coal in combination with biomass, liquid, or gaseous fuels. We have redefined the coal subcategory to include boilers that burn any solid fossil fuel and no more than 15 percent biomass on an annual heat input basis. “Solid fossil fuels” has been defined to include, but not limited to, coal, petroleum coke, coal refuse, and tire derived fuel (TDF). Similarly, we have revised the biomass subcategory to account for boilers that may burn biomass and secondary materials. The biomass subcategory includes boilers combusting at least 15 percent of biomass. This definition differentiates these primarily biomass-fired boilers from the coal subcategory. Additionally, the oil subcategory has been revised to include boilers that burn any liquid fuel but are not included in either the coal or biomass subcategories.

Based on new data submitted during the public comment period, EPA has determined that area source boilers may combust secondary materials. Data submitted indicates that as much as 15 percent of secondary materials, or alternative traditional fuel, may be mixed without causing problems with boiler operations. We wished to differentiate boilers combusting greater than 15 percent of biomass from the remaining subcategories, as these fuels will have higher rates of organic HAP due to the higher moisture content of biomass compared to fossil fuel. The revised definitions for the coal, biomass and oil subcategories clarify this by establishing the fuel type and the input ratio of each fuel type combusted. Therefore, the revised definitions more accurately reflect EPA’s intent to include and account for boilers combusting secondary materials in the coal, biomass, and oil subcategories and the effect of biomass on the combustion process.

Comment: A number of commenters requested that EPA provide exemptions for specific unit types, including limited use boilers, recovery boilers, hot water heaters, boilers firing ultra low sulfur #2 fuel oil, and boilers with a heat input capacity of less than 1 MMBtu/h. Other commenters stated that EPA is not justified in providing an exemption for gas-fired boilers.

Response: As noted in Section VII of the proposed June 2010 rule, 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). Notably, gas-fired units are not included in the source category listing for area source boilers. Without such a listing, EPA cannot address gas-fired boilers in this regulation. We have also included in this final rule an exemption for hot water heaters because these units are, as defined in this final rule, considered residential boilers. In addition, recovery boilers would be exempt because they are regulated under another section 112 MACT standard (*See* 40 CRF part 63, subpart MM).

Conversely, EPA is required to set standards for other unit types, including limited use boilers and boilers firing ultra low sulfur fuel oil. These boilers are included in the source category listing for CAA section 112(d)(2) and emit the pollutants identified in CAA section 112(c)(3). As discussed above, EPA has set appropriate MACT and GACT limits to boilers based on fuel type and size, including area source boilers with a heat input capacity of less than 10 MMBtu/h. EPA also notes that waste heat boilers have been excluded from the definition of boiler.

G. Startup, Shutdown, and Malfunction

Comment: Several commenters stated that a separate standard must be developed for periods of startup and shutdown. Commenters stated that requiring emission limits during SSM directly conflicts with the requirement that MACT be achievable and is technically feasible; therefore EPA could not require emission limits during periods of SSM. Some commenters requested a separate standard for CO for startup; at least one commenter specifically stated that many area source boilers must operate under conditions driven by safety considerations, operational concerns, and warranty requirements that would likely generate unavoidable increases in CO emissions during startup and shutdown. The commenter therefore concluded that requiring a CO emission limit during startup and shutdown would not only be technically unachievable, but would promote unsafe and improper operation. Several commenters suggested that work practice standards are more appropriate than emission limits, citing a lack of relevant data for periods of SSM. Other commenters specifically objected to EPA’s decision to base the SSM requirements on data from the proposed major source NESHAP for industrial, commercial, and institutional boilers and stated that the data from the proposed major source rule cannot be applied to area sources.

Response: EPA has considered these comments and has revised this final rule to incorporate a work practice standard for periods of startup and shutdown. As part of the development of the proposed rule, we reviewed the cost information for CO CEMS provided by commenters on the NESHAP for major source boilers and determined that requiring CO CEMS for units with heat input capacities greater or equal to 100 MMBtu/hr was reasonable. However, EPA has revised this final rule to only require emission limits for mercury and CO for coal-fired boilers. Furthermore, we are only requiring sources to perform a work practice standard, following the manufacturer's recommended procedures, to demonstrate compliance with the emission limits for area source coal-fired boilers during periods of startup and shutdown. Based on the available dataset for facilities in the affected area source category, EPA determined that there are currently no existing coal-fired boilers with a heat input capacity greater than 100 MMBtu/h located at area sources. Coal-fired boilers with a heat input capacity of greater than 50 MMBtu/h are generally major sources of HAP. Therefore, requiring CEMS for boilers of this size is unnecessary for the defined source category.

In lieu of CEMS, we also considered whether requirements for performance testing would be feasible for area source boilers during periods of startup and shutdown. Upon review of these requirements, 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. Therefore, a separate standard must be developed for these periods.

In regards to malfunctions, EPA had previously determined in the development of the proposed rule 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. As discussed in Section III.E of this preamble, EPA has added to this final rule an affirmative defense for civil penalties for exceedances of numerical emission limits that are caused by malfunctions.

Therefore, as allowed under CAA section 112(h), we are requiring a work practice standard for all coal-fired area source boilers during periods of startup and shutdown. The work practice standard requires following the boiler manufacturer's specifications for periods of startup and shutdown.

H. Compliance Requirements

Rationale for Demonstrating Compliance

Comment: Several commenters expressed concern that, given the large numbers of boilers that would be affected by the proposed rule and the limited capacity of existing vendors, contractors, and engineers, a 3-year time period would not be sufficient to allow completion of all of the required modifications.

Response: EPA has re-evaluated the compliance dates for this final rule following the revised MACT and GACT standards. We have revised the initial compliance dates for existing affected sources according to the applicable provisions for each affected source (e.g., work practice or management practice standards, emission limits, and/or an energy assessment), as discussed in Section VI.E of this preamble. EPA has determined that existing sources subject to a work practice standard of a tune-up must comply with this final rule no later than one year after publication of this final rule. We have determined that one year is adequate time for affected sources to meet the work practice or management practice standard, which includes a tune-up based on the manufacturer's recommendations. Existing sources subject to an emission limit or an energy assessment requirement are required to comply with this final rule no later than 3 years after publication of the final rule. Section 112(i)(3)(B) allows EPA, on a case-by-case basis to grant an extension permitting an existing source up to one additional year to comply with standards if such additional period is necessary for the installation of controls. The EPA feels that this provision is sufficient for those sources where the 3-year deadline would not provide adequate time to retrofit as necessary to comply with the requirements of the standard.

Comment: Commenters objected to proposed requirements to use CEMS and in some circumstances COMS. Commenters stated that these requirements are extremely burdensome on area sources considering the testing requirements and costs, and that the requirements for CO CEMS for units less than 100 MMBtu/h are too onerous. Commenters noted that many units at this size in the industrial and institutional sector do not operate frequently; therefore the cost of installing CO CEMS was not justified for units with such limited operation. Other commenters argued that requiring boilers to test for CO poses a significant regulatory burden. Several commenters stated that the proposed testing frequency was burdensome.

Response: EPA has considered these comments, and we have revised the proposed continuous compliance requirements to not require a CO CEMS for area source boilers. Per the revised MACT and GACT determinations, this final rule only requires emission limits for mercury and CO for coal-fired units. Therefore, for new and existing coal units with a heat input capacity greater than 10 MMBtu/h, we are requiring stack testing every 3 years to demonstrate compliance with the CO emission limits. In the development of the proposed rule, we reviewed the cost information for CO CEMS provided by commenters on the NESHAP for major source boilers and determined that requiring CO CEMS for units with heat input capacities greater or equal to 100 MMBtu/h was reasonable. However, based on a review of the available dataset for facilities in the affected area source category, we have determined that there are currently no existing coal-fired boilers with a heat input capacity greater than 100 MMBtu/h located at area sources. Therefore, requiring CEMS for coal-fired boilers of this size is unnecessary for the defined source category. Additionally, boilers in the biomass and oil subcategories with a heat input capacity greater than 10 MMBtu/h are not required to meet emission limits for CO in this final rule; these boilers are subject to the management practice standards in Table 2 of 40 CFR part 63, subpart JJJJJJ, and therefore, no CO testing is required for these units.

I. Cost/Economic Impacts

Comment: Multiple commenters stated that the economic impacts of the proposed rule were significantly underestimated. Many commenters stated that the CO limits would require costly controls, and specifically, that the cost of particulate control for biomass boilers was severely underestimated. Other commenters stated that EPA made erroneous assumptions in performing the cost calculations. For instance, one commenter stated that EPA does not have enough data to support the assumption that fabric filters alone will be sufficient for area source coal-fired boilers to meet the proposed mercury limit.

Response: In light of changes to this final rule, EPA believes that these concerns are no longer an issue. We have revised the costs estimates for this final rule to reflect EPA's determination of the final MACT standards for coal-fired boilers and GACT standards for biomass and oil-fired boilers. For instance, EPA is only requiring particulate emission limits for new boilers with a heat input capacity of greater than 10 MMBtu/h; smaller boilers must only meet the management practice standard of a tune-up. These changes have significantly decreased the costs presented in the proposed June 2010 rule. Additionally, commenters provided additional cost information during the public comment period; EPA has incorporated this information into the analysis for this final rule. Based on this re-analysis, EPA has determined that fabric filter controls are generally available and cost effective for new area source boilers. As noted previously, new area source boilers with a heat input capacity of 30 MMBtu/h or greater are subject to the NSPS for boilers (either subpart Db or Dc of 40 CFR part 60), which regulate emissions of PM and require performance testing. Furthermore, new coal-fired area source boilers will likely require a PM control device to comply with the proposed mercury MACT standard and required performance testing. We determined in the context of the major source rulemaking, and from further analysis of new data submitted during the public comment period, that fabric filters are the most effective technology employed by industrial, commercial, and institutional boilers for controlling mercury and particulate emissions. Therefore, EPA has determined it is appropriate and cost-effective to estimate the cost of compliance based on fabric filters for new area source boilers.

Comment: Some commenters stated that this final rule would have substantial impacts on rural communities. Commenters noted that many rural communities rely upon or significantly benefit from the use of biomass boilers for energy at manufacturing facilities, schools and hospitals. These commenters stated that the proposed rule will negatively impact both boiler owners and fuel suppliers in these communities. Similarly, other commenters stated that this final rule would have a significant adverse impact on the use of biomass renewable energy throughout the economy.

Response: In light of the changes made to the final regarding biomass-fired area source boilers, we believe these concerns are no longer an issue. In the final rule, existing biomass area source boilers are only subject to the management practice of a tune-up and only existing biomass-fired area source boilers with a heat input capacity of 10 MMBtu/h or greater are required to have an energy assessment performed. There are no testing or monitoring requirements in this final rule for existing biomass-fired area source boilers. For a typical existing biomass-fired boilers, this change resulted in reducing the annualized cost of compliance from about $420,000 to about $2,200.

New biomass-fired area source boilers with a heat input capacity of 10 MMBtu/h or greater are only subject to a PM emission limit which requires a PM test be conducted once every 3 years.

J. Title V Permitting Requirements

In response to comments received and after further evaluation of the record, EPA has decided to exempt all area sources subject to this subpart from title V permitting. In evaluating the record, we have determined that observations and data we have relied upon in other rulemakings for distinguishing between sources that became synthetic area sources due to controls and other synthetic and natural area sources did not necessarily apply to this source category. Therefore, we lack sufficient information at this juncture to distinguish the sources which have applied controls to boilers in order to become area sources from other synthetic and natural area sources. As a result, the rationale for exempting most area sources subject to this rule as explained in the proposal preamble (*see* pages 31910 to 31913) is also now relevant for sources which we proposed to permit. Thus, no area sources subject to this subpart are required to obtain a title V permit as a result of being subject to this subpart.

A source subject to this subpart may be subject to title V permitting for another reason or reasons, e.g., being located at a major source. If more than one requirement triggers a source's obligation to apply for a title V permit, the 12-month timeframe for submitting a title V application is triggered by the requirement which first causes the source to be subject to title V. See 40 CFR 70.3(a) and (b) or 71.3(a) and (b).

VI. Relationship of This Action to CAA Section 112(c)(6)

CAA section 112(c)(6) 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 mercury. (The POM emitted is composed of 16 polyaromatic hydrocarbons (PAH).) 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 (April 10, 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 by-products 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 does form during combustion is further controlled by the various post-combustion controls. The add-on PM control systems (fabric filter) used to reduce mercury and/or PM emissions further reduce emissions of these organic pollutants, as is evidenced by performance data. Specifically, the emission tests obtained at currently operating major source boilers show that the MACT regulations for coal-fired area source boilers will reduce Hg emissions by about 86 percent. It is, therefore, reasonable to conclude that POM emissions from coal-fired area source boilers will be substantially controlled.

In lieu of establishing numerical emissions limits for pollutants such as POM, we regulate surrogate substances. While we have not identified specific numerical limits for POM, we believe CO serves as an effective surrogate for this HAP, because CO, like POM, is formed as a product 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 establish numerical emissions limits for POM with respect to coal-fired area source boilers to satisfy CAA section 112(c)(6).

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

VII. Summary of the Impacts of This Final Rule

A. What are the air impacts?

Table 3 of this preamble illustrates, for each subcategory, the estimated emissions reductions achieved by this rule (i.e., the difference in emissions between an area source boiler controlled to the MACT/GACT level of control and boilers at the current baseline) for new and existing sources. Nationwide emissions of total HAP (HCl, hydrogen fluoride, non-mercury metals, mercury, and VOC (for organic HAP) will be reduced by about 667 tpy for existing units and 74 tpy for new units. Emissions of mercury will be reduced by about 88 pounds per year for existing units and by about 9 pounds per year for new units. Emissions of filterable PM will be reduced by about 2,300 tpy for existing units and 280 tpy for new units. Emissions of non-mercury metals (i.e., antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium) will be reduced by about 280 tpy for existing units and will be reduced by 40 tpy for new units. Additionally, EPA has estimated that conducting an biennial tune-up will likely reduce emissions of organic HAP as a result of improved combustion and reduced fuel use. POM reductions are represented by 7–PAH, a group of polycyclic aromatic hydrocarbons. EPA estimates that the work practices, management practices, and CO emission limits may reduce emissions of 7–PAH by 8 tpy for existing units and by 1 tpy for new units. A discussion of the methodology used to estimate baseline emissions and emissions reductions is presented in "Estimation of Impacts for Industrial, Commercial, and Institutional Boilers Area Source NESHAP" in the docket.

TABLE 3—SUMMARY OF HAP EMISSIONS REDUCTIONS FOR EXISTING AND NEW SOURCES (TPY)

Source	Subcategory	PM	Non mercury metals [a]	Mercury	POM [b]
Existing Units	Coal	1,092	4	0.003	0.2
	Biomass	815	11	0.003	5
	Oil	349	269	0.04	3
New Units	Coal	7	0.03	0.0001	0.02
	Biomass	121	2	0.0002	0.5
	Oil	149	36	0.004	0.5

[a] Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.
[b] POM is represented by total emissions of polycyclic aromatic hydrocarbons (7–PAH). It is assumed that compliance with work practice standard and management practice will reduce fuel usage by 1 percent, which may reduce emissions of 7–PAH by an equivalent amount.

B. What are the cost impacts?

To estimate the national cost impacts of this rule for existing sources, EPA developed several model boilers and determined the cost of control for these model boilers. EPA assigned a model boiler to each existing unit based on the fuel, size, and current controls. The analysis considered all air pollution control equipment currently in operation at existing boilers. Model costs were then assigned to all existing units that could not otherwise meet the proposed standards. The resulting total national cost impact of this rule for existing units is $487 million dollars in total annualized costs. The total annualized costs (new and existing) for installing controls, conducting biennial tune-ups and an energy assessment, and implementing testing and monitoring requirements is $535 million. Table 4 of this preamble shows the total annualized cost impacts for each subcategory.

TABLE 4—SUMMARY OF ANNUAL COSTS FOR NEW AND EXISTING SOURCES

Source	Subcategory	Estimated/projected No. of affected units	Total annualized cost (TAC) ($10^6/yr) [a]
Existing Units	Coal	3,710	37
	Biomass	10,958	24
	Oil	168,003	374
Facility Energy Assessment	All	....	52
New Units [b]	Coal	155	0.4
	Biomass	200	2.6
	Oil	6,424	45

[a] TAC does not include fuel savings from improving combustion efficiency.
[b] Impacts for new units assume the number of units online in the first 3 years of this rule (2010 to 2013).

Using Department of Energy projections on fuel expenditures, as well as the history of installation dates of area source boilers in the dataset, the number of additional boilers that could be potentially constructed was estimated. The resulting total national cost impact of this proposed rule on new sources by the third year, 2013, is $48 million dollars in total annualized costs. When accounting for a 1 percent fuel savings resulting from improvements to combustion efficiency, the total national cost impact on new sources is −$3.6 million.

A discussion of the methodology used to estimate cost impacts is presented in the memorandum, "Estimation of Impacts for Industrial, Commercial, and Institutional Boilers Area Source NESHAP" in the Docket.

C. What are the economic impacts?

The economic impact analysis (EIA) that is included in the RIA shows that the expected prices for industrial sectors could be 0.01 percent higher and domestic production may fall by less than 0.01 percent. Because of higher domestic prices, imports may rise by less than 0.01 percent. Energy prices will not be affected.

Social costs are estimated to be also $0.49 billion in 2008 dollars. This is estimated to made up of a $0.24 billion loss in domestic consumer surplus, a $0.25 billion loss in domestic producer surplus, a $0.004 billion increase in rest of the world surplus, and a $0.003 billion net loss associated with new source costs and fuel savings not modeled in a way that can be used to attribute it to consumers and producers.

EPA performed a screening analysis for impacts on small entities by comparing compliance costs to sales/revenues (e.g., sales and revenue tests). EPA's analysis found the tests were typically higher for small entities included in the screening analysis. EPA has prepared an Initial Regulatory Flexibility Analysis (IRFA) that discusses alternative regulatory or policy options that minimize this final rule's small entity impacts. It includes key information about key results from the Small Business Advocacy Review (SBAR) panel. The IRFA is discussed in section 5.2 of the report "Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heater" located in the docket. EPA has also prepared A Final Regulatory Flexibility Analysis (FRFA) that is found in section 5 of the RIA.

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.

D. What are the benefits?

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 $210 million to $520 million (2008$, 3 percent discount rate) in the implementation year (2014). The monetized benefits at a 7 percent discount rate are $190 million to $470 million (2008$). Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[8] A summary of the monetized benefits estimates at discount rates of 3 percent and 7 percent are provided in Table 6 of this preamble. A summary of the avoided health benefits are provided in Table 7 of this preamble.

TABLE 6—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER AREA SOURCE RULE

[Millions of 2008$] [1]

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
Direct $PM_{2.5}$	678	$79 to $190	$72 to $180
SO_2	3,197	130 to 320	120 to 290
Total		210 to 520	190 to 470

[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 HAP are not included. These estimates do not include energy disbenefits valued at less than $1 million. These benefits reflect existing boilers and 6,779 new boilers anticipated to come online by 2014.

TABLE 7—SUMMARY OF THE AVOIDED HEALTH INCIDENCES FOR THE FINAL BOILER MACT

	Avoided health incidences
Avoided Premature Mortality	24 to 61
Avoided Morbidity:	
Chronic Bronchitis	17
Acute Myocardial Infarction	40
Hospital Admissions, Respiratory	6
Hospital Admissions, Cardiovascular	13
Emergency Room Visits, Respiratory	21
Acute Bronchitis	38
Work Loss Days	3,200
Asthma Exacerbation	420
Minor Restricted Activity Days	19,000
Lower Respiratory Symptoms	460
Upper Respiratory Symptoms	350

Note: All estimates are for the implementation year (2014), and are rounded to two significant figures and whole numbers. All fine particles are assumed to have equivalent health effects. Benefits from reducing HAP are not included. These benefits reflect existing boilers and 6,779 new boilers anticipated to come online by 2014.

[8] Roman *et al.,* 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268—2274.

These quantified benefits estimates represent the human health benefits associated with reducing exposure to $PM_{2.5}$. The PM 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 $PM_{2.5}$-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 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 SO_2 are the dominant $PM_{2.5}$ precursors affected by this 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, SO_2 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 SO_2 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 SO_2 emissions.

Furthermore, CAMx modeling allows us to model the reduced mercury deposition that would occur as a result of the estimated reductions of mercury emissions. Although we are unable to model mercury methylation and human consumption of mercury-contaminated fish, the mercury deposition maps provide an improved qualitative characterization of the mercury 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 judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. For this rule, we cite two key empirical studies, one based on the American Cancer Society cohort study[10] and the extended Six Cities cohort study.[11] In the RIA for this 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 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 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 $\mu g/m^3$. Using the Laden, *et al.,* (2006) study, 34 percent of the population is exposed above the LML of 10 $\mu g/m^3$. 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 1,100 tons of CO, 340 tons of HCl, 8 tons of HF, 90 pounds of mercury, and 320 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 rule, which is available in the docket.

In addition, the monetized benefits estimates provided in Table 6 do not reflect the disbenefits associated with increased electricity usage from operation of the control devices. We estimate that the increases in emissions of CO_2 would have disbenefits valued at less than $1 million at a 3 percent discount rate (average). CO_2-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 CO_2 disbenefits using discount rates of 5 percent (average), 2.5 percent (average), and 3 percent (95th percentile).

[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.*

[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.

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 RIAs 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.

E. What are the water and solid waste impacts?

EPA estimated that no additional water usage would result from the MACT floor level of control or GACT requirement. The fabric filter, multiclone, or combustion control devices used to meet the standards of this rule do not require any water to operate, nor do they generate any wastewater.

EPA estimated the additional solid waste that would result from this rule to be 1,800 tpy for existing sources due to the dust and fly ash captured by mercury and PM control devices. The cost of handling the additional solid waste generated from existing sources is $75,700 per year. For new sources installed by 2013, the EPA estimated the additional solid waste that would result from this rule to be 540 tpy for new sources due to the dust and fly ash captured by mercury and PM control devices. The cost of handling the additional solid waste generated from new sources is $22,900 per year. These costs are also accounted for in the control costs estimates.

A discussion of the methodology used to estimate impacts is presented in "Estimation of Impacts for Industrial, Commercial, and Institutional Boilers Area Source NESHAP" in the Docket.

F. What are the energy impacts?

EPA expects an increase of approximately 25 million kWh in national annual energy usage from existing sources as a result of this rule. The increase results from the electricity required to operate control devices installed to meet this rule, such as fabric filters. Additionally, for new sources installed by 2013, EPA expects an increase of approximately 8 million kWh in national annual energy usage in order to operate the control devices.

The Department of Energy has conducted energy assessments at selected manufacturing facilities and reports that facilities can reduce fuel/energy use by 10 to 15 percent by using best practices to increase their energy efficiency. Additionally, the EPA expects work practice standards, such as boiler tune-ups, and combustion controls such as new replacement burners, will improve the efficiency of boilers. EPA estimates existing area source facilities can save 20 trillion Btu of fuel each year. For new sources online by 2013, the EPA estimates 2.3 trillion BTU per year of fuel can be conserved. This fuel savings estimate includes only those fuel savings resulting from liquid and coal fuels and it is based on the assumption that the work practice standards will achieve 1 percent improvement in efficiency.

VIII. Statutory and Executive Order Review

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

Under section 3(f)(1) of Executive Order 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 OMB for review under EO 12866 and any changes in response to OMB recommendations have been documented in the docket for this action.

In addition, EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the Regulatory Impact Analysis (RIA) report. 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 AREA SOURCE RULE IN 2014

[Millions of 2008$] [1]

	3% Discount rate	7% Discount rate
Final MACT/GACT Approach: Selected		
Total Monetized Benefits [2]	$210 to $520	$190 to $470
Total Social Costs [3]	$490	$490
Net Benefits	−$280 to $30	−$300 to −$20
Non-monetized Benefits	1,100 tons of carbon monoxide 340 tons of HCl 8 tons of HF 90 pounds of mercury 320 tons of other metals <1 gram of dioxins/furans (TEQ) Health effects from SO_2 exposure Ecosystem effects Visibility impairment	
Proposed MACT Approach: Alternative		
Total Monetized Benefits [2]	$200 to $490	$180 to $440
Total Social Costs [3]	$850	$850
Net Benefits	−$650 to −$360	−$670 to −$410
Non-monetized Benefits	1,100 tons of carbon monoxide 340 tons of HCl 8 tons of HF 90 pounds of mercury 320 tons of other metals	

SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE BOILER AREA SOURCE RULE IN 2014—Continued

[Millions of 2008$] [1]

	3% Discount rate	7% Discount rate
	<1 gram 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 SO_2. 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 less than $1 million.

[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 rule have been submitted for approval to OMB under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The information collection requirements are not enforceable until OMB approves them. The ICR document prepared by EPA has been assigned EPA ICR number 2253.01. The recordkeeping and reporting requirements in this rule are based on the information collection requirements in EPA's NESHAP General Provisions (40 CFR part 63, subpart A). The recordkeeping and reporting requirements in the General Provisions are mandatory pursuant to CAA section 114 (42 U.S.C. 7414). All information other than emissions data submitted to EPA pursuant to the information collection requirements for which a claim of confidentiality is made is safeguarded according to CAA section 114(c) and EPA's implementing regulations at 40 CFR part 2, subpart B.

This NESHAP would require applicable one-time notifications according to the NESHAP General Provisions. Facility owners or operators are required to include compliance certifications for the work practices and management practices in their Notifications of Compliance Status. Recordkeeping is required to demonstrate compliance with emission limits, work practices, management practices, monitoring, and applicability provisions. New affected facilities are required to comply with the requirements for startup, shutdown, and malfunction reports and to submit a compliance report if a deviation occurred during the semiannual reporting period.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of this Subpart JJJJJJ. 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 reasonably 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 $407 million. This includes 2.7 million labor hours per year at a cost of $254 million and total non-labor capital costs of $153 million per year. This estimate includes initial and triennial performance tests, conducting and documenting an energy assessment, conducting and documenting a tune-up, semiannual excess emission reports, maintenance inspections, developing a monitoring plan, notifications, and recordkeeping. Monitoring, testing, tune-up and energy assessment costs were also included in the cost estimates presented in the control cost impacts estimates in Section VII.B 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 286,000 hours per year at a total labor cost of $13 million per year. Burden is defined at 5 CFR 1320.3(b).

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

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) the final rule.

The rule is intended to reduce emissions of HAP as required under section 112 of the CAA. Section II.A of this preamble describes the reasons that EPA is finalizing this action.

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 the final rule's preamble.

The primary comments on the IRFA were provided by SBA, with the remainder of the comments generally supporting SBA's comments. Those comments applicable to the proposal regarding area source boilers included the following: EPA should have adopted additional subcategories, including the following: Unit design type (*e.g.* 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; and EPA's proposed emissions standards are too stringent.

In response to the comments on the IRFA and other public comments, EPA made the following changes to the final rule. EPA is promulgating management practice standards requiring the implementation of a boiler tune-up program for area source boilers in the biomass and oil subcategories instead of the proposed CO emission limits. This change will significantly reduce the monitoring and testing costs for existing and new biomass-fired and oil-fired area source boilers. EPA also decreased monitoring and testing costs for coal-fired area source boilers by eliminating the CO CEMS requirement for boilers greater than 100 MMBtu/h. The final rule also includes work practice standards or management practice standards, instead of emission limits, for new area source boilers less than 10 MMBtu/h. Finally, EPA is finalizing emission limits that are less stringent than the proposed limits. The emission limit changes are largely due to the changes in 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 the final rule's preamble.

Table 5 of this preamble summarizes the EPA estimates of the number of area source facilities expected to be affected by the area source rule. EPA does not have sufficient information to estimate the number of small entities expected to be covered by the area source rule.

As discussed in section 5.1 of the RIA for this rule, using these cost data and the Census estimates of average establishment receipts, a substantial number of SUSB NAICS/enterprise categories have ratios over 3%. The following types of representative small area source public facilities would have cost-to-revenue ratios exceeding 1 percent but below 3 percent: Other public facilities (ratio >1.7 percent) and churches (ratio = 1.5 percent).

TABLE 5—ESTIMATED AFFECTED FACILITIES USING 13 STATE BOILER INSPECTOR INVENTORY: AREA SOURCES

SIC	Total number of affected facilities in SIC Code
01	0
02	247
07	0
09	0
14	83
16	0
17	247
20	5,733
23	83
24	2,676
26	0
40	329
41	0
42	83
43	0
44	0
45	0
47	0
48	741
50	165
51	247
52	0
53	494
54	0
55	801
56	0
57	0
58	905
59	288
60	329
64	0
65	2,878
70	4,893
72	2,138
73	165
75	1,606
76	0
79	1,151
80	15,293
81	0
82	33,303
83	0
84	165
86	3,330
87	666
91 to 98	5,098
Unknown	576

The information collection activities in this ICR include initial and triennial stack tests, fuel analyses, operating parameter monitoring, continuous oxygen monitoring for all coal-fired area source boilers greater than 10 MMBtu/h, certified energy assessments for area source facilities having a boiler greater than 10 MMBtu/h, biennial tune-ups, preparation of a startup, shutdown, malfunction plan (SSMP), 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 13 states' inventories of boilers, there are an estimated 92,000 existing facilities with affected boilers. It is estimated that 53 percent are located in the private sector and the remaining 47 percent are located in the public sector. Of these, only about 0.3 percent of the area source facilities are subject to emission limits and the testing and monitoring requirements in the final rule. A table included in the FRFA summarizes the types and number of each type of small entities expected to be affected by the area 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.

While EPA did make significant changes based on public comment, EPA is maintaining, but clarifying, the energy assessment requirement. Some changes to the energy assessment requirement that will reduce costs for small entities include a the following provisions: The energy assessment for facilities with affected boilers 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 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, the final rule allows facilities to use a previously completed energy assessment to satisfy the energy assessment requirement.

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.*

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 this final 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 this 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 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 Boiler Area Source 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 rulemaking is CAA section 112. Title III of the CAA 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 requires us to establish NESHAP for both major and area sources of HAP that are listed for regulation under CAA section 112(c). CAA section 112(k)(3)(B) calls for EPA to identify at least 30 HAP which, as the result of emissions from area sources, pose the greatest threat to public health in the largest number of urban areas. CAA section 112(c)(3) requires EPA to list sufficient categories or subcategories of area sources to ensure that area sources representing 90 percent of the emissions of the 30 urban HAP are subject to regulation.

Under CAA section 112(d)(5), we may elect to promulgate standards or requirements for area sources based on GACT used by those sources to reduce emissions of HAP. Determining what constitutes GACT involves considering the control technologies and management practices that are generally available to the area sources in the source category. We also consider the standards applicable to major sources in the analogous source category and, as appropriate, the control technologies and management practices at area and major sources in similar categories, to determine if the standards, technologies, and/or practices are transferable and generally available to area sources. In determining GACT for a particular area source category, we consider the costs and economic impacts of available control technologies and management practices on that category.

While GACT may be a basis for standards for most types of HAP emitted from area source, CAA section 112(c)(6) requires that source categories accounting for emissions of the HAP listed in CAA section 112(c)(6) be subject to standards under CAA section 112(d)(2) for the listed pollutants. Thus, CAA section 112(c)(6) requires that emissions of each listed HAP for the listed categories be subject to MACT regulation. The CAA section 112(c)(6) list of source categories includes industrial boilers and institutional/commercial boilers. Within these two source categories, coal combustion, oil combustion, and wood combustion have been on the CAA section 112(c)(6) list because of emissions of mercury and POM. We currently believe that regulation of coal-fired boilers will ensure that we fulfill our obligation under CAA section 112(c)(6) with respect to mercury and POM reductions. Consequently, we deem it reasonable to regulate the coal-fired boilers under MACT, rather than the biomass and oil-fired boilers, to obtain additional mercury and POM reductions towards achieving the CAA section 112(c)(6) obligation. We are regulating biomass-fired and oil-fired boilers under GACT.

This NESHAP will apply to all existing and new industrial boilers, institutional boilers, and commercial boilers located at area sources. 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 emission limits for existing area source boilers are only applicable to area source boilers that have a designed heat input capacity of 10 MMBtu/h or greater. The regulatory alternative upon which the standards are based represents the MACT floor for the listed CAA section 112(c)(6) pollutants (mercury and POM) for coal-fired units and GACT for the other urban HAP which formed the basis for the listing of these two area source categories. The standards will require new coal-fired boilers to meet MACT-based emission limits for mercury and CO (as a surrogate for POM) and GACT-based emission limits for PM (as a surrogate for urban metals). New biomass and oil-fired boilers will be required to meet GACT for CO, which are tune-ups, and GACT-based emission limits for PM. Existing large coal-fired boilers will be required to meet MACT-based emission limits for mercury and CO for coal-fired units, and existing large biomass and oil-fired boilers will be subject to GACT, which is a tune-up. As allowed under CAA section 112(h), a work practice standard requiring the implementation of a tune-up program is being established for existing and new area source boilers with a designed heat input capacity of less than 10 MMBtu/h. An additional "beyond-the-floor" standard is being established for existing area source facilities having an affected boiler with a heat input capacity of 10 MMBtu/h or greater that requires the performance of an energy assessment on the boiler and the facility to identify cost-effective energy conservation measures.

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: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters" 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 $0.49 billion (2008 dollars).

It is estimated that 3 years after implementation of this final rule, HAP will be reduced by hundreds of tons, including reductions in metallic HAP including mercury, hydrochloric acid, hydrogen fluoride, and several other organic HAP from area source boilers. 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 reductions in $PM_{2.5}$ and in SO_2 that will occur, including 678 tons of $PM_{2.5}$ and 3,197 tons of SO_2. These reductions occur within 3 years after the implementation of the regulation and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) is a reduction in premature mortality. Other health effects associated with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks, and work-lost days (*i.e.,* days when employees are unable to work). While we are unable to monetize the benefits associated with the HAP emissions reductions, we are able to monetize the benefits associated with the $PM_{2.5}$ and SO_2 emissions reductions. For $SO_{2.5}$ and $PM_{2.5}$, we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2013 associated with the implementation of this final rule range from $0.21 billion (2008 dollars) to $0.52 billion (2008 dollars) when using a 3 percent discount rate (or from $0.19 billion (2008 dollars) to $0.47 billion (2008 dollars) when using a 7 percent discount rate. The general approach used to value benefits is discussed in more detail in Section VII.D of 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 Unfunded Mandates Reform Act 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 this final rule are discussed in Section VII.C of 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 in Section VII.C of this preamble.

4. Effects on the National Economy

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

The nationwide economic impact of this final rule is presented in the Economic Impact Analysis chapter (Section 4) of the RIA in the docket. This analysis provides estimates of the effect of this final rule on some of the categories mentioned above. The results of the economic impact analysis are summarized in Section VII.C of this preamble. The results show that there will be a small impact on prices and output (less than 0.01 percent). 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 Reform 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. Consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA has initiated consultations with governmental entities affected by this rule. EPA invited the following 10 national organizations representing state and local elected officials to a meeting held on March 24, 2010 in Washington, DC: (1) National Governors Association; (2)

National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations of elected state and local officials have been identified by EPA as the "Big 10" organizations appropriate to contact for purpose of consultation with elected officials. The purposes of the consultation were to provide general background on the proposal, answer questions, and solicit input from state/local governments. During the meeting, officials expressed uncertainty with regard to how boilers owned/operated by state and local entities would be impacted, as well as with regard to the potential burden associated with implementing this final rule on state and local entities. To that end, officials requested and EPA provided (1) model boiler costs, (2) inventory of area source boilers (coal, oil, biomass only) for the 13 states for which we have an inventory, and (3) information on potential size of boilers used for various facility types and sizes. EPA has not received additional questions or requests from state or local officials.

Consistent with section 205, EPA identified and considered a reasonable number of regulatory alternatives. Because an initial screening analysis for impact on small entities indicated a likely significant impact for substantial numbers, EPA convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of this final rule. As part of that process, EPA considered several options. Those options included establishing emission limits, establishing work practice standards, and establishing work practice standards and requiring an energy assessment. The regulatory alternative selected is a combination of the options considered and includes provisions regarding each of the SBAR Panel's recommendations for area source boilers. The recommendations regard the use of subcategories, work practice standards, and compliance costs (see section IX.C of this preamble for more detail on the RFA).

EPA determined subcategories based on boiler type to be appropriate because different types of units have different emission characteristics which may affect the feasibility and effectiveness of emission control. Thus, this final rule identifies three subcategories of area source boilers: (1) Boilers designed for coal firing, (2) boilers designed for biomass firing, and (3) boilers designed for oil firing.

The emission limits for existing and new area source boilers are only applicable to area source boilers that have a designed heat input capacity of 10 MMBtu/h or greater. A work practice standard (for mercury from coal-fired boilers and for POM from all boilers) or management practice (for all other HAP, including mercury from biomass-fired and oil-fired boilers) requiring the implementation of a tune-up program is being established for existing area source boilers with a designed heat input capacity of less than 10 MMBtu/h. The regulatory alternative upon which the standards are based represents the MACT floor for mercury and POM (CO is used as a surrogate for POM) for coal-fired boilers, and GACT for the other urban HAP (PM is used as a surrogate for urban HAP metals and CO is used as a surrogate for urban organic pollutants) for new coal, biomass, and oil-fired boilers. An additional "beyond-the-floor" standard is being established for existing area source facilities having an affected boiler with a heat input capacity of 10 MMBtu/h or greater that requires the performance of an energy assessment on the boiler and the facility to identify cost-effective energy conservation measures.

The use of surrogate pollutants will result in reduced compliance costs because testing is only required for the surrogate pollutants (*i.e.,* CO and PM) versus for the HAP (i.e., POM and metals). The work practice standard/management practice also will result in reduced compliance costs with respect to monitoring/testing for the smaller existing area source boilers. EPA's exemption of area source facilities from title V permit requirements also will reduce burden on area source boiler facilities.

This rule is not subject to the requirements of section 203 of the UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have boilers that will be affected by this final rule, EPA's analysis shows that other public facilities that are located at area source facilities owned by small entities will not have cost-to-revenue ratios exceeding 10 percent. Hospitals' and schools' revenue tests fall below 1 percent. Because this final rule's requirements apply equally to boilers owned and/or operated by governments and to boilers owned and/or operated by private entities, there will be no requirements that uniquely apply to such governments or impose any disproportionate impacts on them.

E. Executive Order 13132: Federalism

Under Executive Order 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or EPA consults with state and local officials early in the process of developing the proposed action.

EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. Accordingly, EPA provides the following federalism summary impact statement as required by section 6(b) of Executive Order 13132.

Based on the estimates in EPA's RIA for today's action, the regulatory option may have federalism implications because the action may impose approximately $276 million in annual direct compliance costs on an estimated 57,000 state or local governments. Boiler inventories for the health services, educational services, and government-owned buildings sectors from 13 States were used to estimate the nationwide number of potentially impacted state or local governments. Because the inventories for these sectors include privately owned and federal government owned facilities, the estimate may include many facilities that are not state or local government owned. Table 8 of this preamble presents estimates of the number of potentially impacted state and local governments and their potential annual compliance costs for each of the three sectors. In addition to an estimate of the total number of potentially impacted facilities, estimates for facilities with small boilers and for facilities with large boilers are presented. Small boilers (boilers with heat input capacity of less than 10 MMBtu/h) will be subject to a work practice standard or management practice that requires a boiler tune-up every 2 years. Large coal-fired boilers (boilers with heat input capacity of 10 MMBtu/h or greater) will be subject to emission limits for mercury and CO. Large biomass and oil-fired boilers will be subject to a biennial boiler tune-up requirement for CO. All facilities with large boilers will be required to conduct a one-time energy assessment.

TABLE 8—STATE AND LOCAL GOVERNMENTS POTENTIALLY IMPACTED BY THE STANDARDS FOR BOILERS AT AREA SOURCE FACILITIES

Sector	Number of potentially impacted facilities			Annual compliance costs to meet standards ($)
	Total	Small	Large	
Health Services	17,206	15,293	1,913	$84 million.
Educational Services	34,052	33,303	749	159 million.
Government-Owned Buildings	5,796	5,098	698	33 million.
Total	57,054	53,694	3,360	276 million.

EPA consulted with state and local officials in the process of developing the action to permit them to have meaningful and timely input into its development. EPA met with 10 national organizations representing state and local elected officials to provide general background on the proposed rule, answer questions, and solicit input from state/local governments. The UMRA discussion in Section IX.D of this preamble includes a description of the consultation. As required by section 8(a) of Executive Order 13132, EPA included a certification from its Federalism Official stating that EPA had met the Executive Order's requirements in a meaningful and timely manner, when it sent the draft of this final action to OMB for review pursuant to Executive Order 12866. A copy of this certification has been included in the public version of the official record for this final action.

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). This final rule imposes requirements on owners and operators of specified area sources and not tribal governments. We do not know of any industrial, commercial, or institutional boilers owned or operated by Indian tribal governments. However, if there are any, the effect of this final rule on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to this action.

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

This action 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. In addition, this action is not subject to Executive Order 13045 because this final rule is based solely on technology performance.

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

This action is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. We estimate no significant changes for the energy sector for price, production, or imports. For more information on the estimated energy effects, please refer to Section VI of this preamble. The analysis is available in the public docket.

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, Section 12(d), 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities, unless to do so would be inconsistent with applicable law or otherwise impractical. The VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency does not use available and applicable VCS.

This final rule involves technical standards. EPA cites the following standards in this final rule: EPA Methods 1, 2, 2F, 2G, 3A, 3B, 4, 5, 5D, 10, 10A, 10B, 17, 19, 29 of 40 CFR part 60; 101A of 40 CFR part 61; and voluntary consensus standards: American Society of Mechanical Engineers (ASME) PTC 19 (manual methods only), American Society for Testing and Materials (ASTM) D6522–00, ASTM D6784–02, ASTM D2234/D2234M–10, ASTM D6323–98, ASTM D2013–04, ASTM D5198–92, ASTM D5865–04, ASTM E711–87, ASTM D3173–03, ASTM E871–82, and ASTM D6722–01.

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 as alternatives for EPA Methods 2F, 2G, 5D, and 19. The search and review results are in the docket for this rule.

The search for emissions measurement procedures identified 16 other voluntary consensus standards. EPA determined that these 16 standards identified for measuring emissions of the HAP or surrogates subject to emission standards in this rule were impractical alternatives to EPA test methods for the purposes of this rule. Therefore, EPA did not adopt these standards for this purpose. The reasons for the determinations for the 16 methods can be found in the docket to this rule.

Table 4 to subpart JJJJJJ of this rule lists the testing methods included in the regulation. Under 40 CFR 63.7(f) and 63.8(f) 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 required 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 EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations, low-income, and tribal populations in the United States.

This action establishes national emission standards for industrial, commercial, and institutional boilers that are area sources. The industrial boiler source category includes boilers used in manufacturing, processing, mining, refining, or any other industry. The commercial boiler source category includes boilers used in commercial establishments such as stores/malls, laundries, apartments, restaurants, theatres, and hotels/motels. The institutional boiler source category includes boilers used in medical centers (*e.g.,* hospitals, clinics, nursing homes), educational and religious facilities (*e.g.,* schools, universities, places of worship), and municipal buildings (*e.g.,* courthouses, arts centers, prisons). There are approximately 92,000 facilities affected by this final rule, most of which are small entities. By the defined nature of the category, many of these sources are located in close proximity to residential areas, commercial centers, and other locations where large numbers of people live and work.

Due to the large number of these sources, their nation-wide dispersal, and the absence of site specific coordinates, EPA is unable to examine the distributions of exposures and health risks attributable to these sources among different socio-demographic groups for this rule, or to relate the locations of expected emission reductions to the locations of current poor air quality. However, this final rule is anticipated to have substantial emissions reductions of toxic air pollutants (*see* Table 2 of this preamble), some of which are potential carcinogens, neurotoxins, and respiratory irritants. This final rule will also result in reductions in criteria pollutants such as CO, PM, SO_2, as well as ozone precursors.

Because of the close proximity of these source categories to people, the substantial emission reductions of air toxics resulting from the implementation of this rule is anticipated to have health benefits for all persons living or going near these types of sources. (Please refer to the RIA for this rulemaking, which is available in the docket.) For example, there will be reductions of mercury emissions which will reduce potential exposures due to the atmospheric deposition of mercury for populations such as subsistence fisherman. In addition, there will be reductions in other air toxics which can cause adverse health effects such as ozone precursors that contribute to "smog." EPA has determined that this rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low-income, or tribal populations.

EPA defines "Environmental Justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and polices. To promote meaningful involvement, EPA has developed an EJ communication strategy to ensure that interested communities have access to this rule, are aware of its content, and have an opportunity to comment. In addition, state and federal permitting requirements will provide state and local governments and communities the opportunity to provide their comments on the permit conditions associated with permitting these sources.

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 this final rule must submit a rule report, which includes a copy of this final rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this 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 this final 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, Intergovernmental relations, Incorporation by reference, 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 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.*

Subpart A—[Amended]

■ 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 Incorporation by reference.

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(b) * * *

(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, table 12 to subpart DDDDD of this part, and table 4 to subpart JJJJJJ of this part.

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(39) ASTM Method 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 Method 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 JJJJJJ 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 JJJJJJ 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 JJJJJJ of this part.

* * * * *

(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 JJJJJJ 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 JJJJJJ 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 JJJJJJ 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 JJJJJJ 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 JJJJJJ 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.

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(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 and Table 5 to subpart JJJJJJ 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 JJJJJJ 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), 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.

(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 JJJJJJ of this part.

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(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 JJJJJJ 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 JJJJJJ 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 JJJJJJ 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 JJJJJJ 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 adding subpart JJJJJJ to read as follows:

Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

Sec.

Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

What This Subpart Covers

§ 63.11193 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler as defined in § 63.11237 that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in § 63.2, except as specified in § 63.11195.

§ 63.11194 What is the affected source of this subpart?

(a) This subpart applies to each new, reconstructed, or existing affected source as defined in paragraphs (a)(1) and (2) of this section.

(1) The affected source is the collection of all existing industrial, commercial, and institutional boilers within a subcategory (coal, biomass, oil), as listed in § 63.11200 and defined in § 63.11237, located at an area source.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler within a subcategory, as listed in § 63.11200 and as defined in § 63.11237, located at an area source.

(b) An affected source is an existing source if you commenced construction or reconstruction of the affected source on or before June 4, 2010.

(c) An affected source is a new source if you commenced construction or reconstruction of the affected source after June 4, 2010 and you meet the applicability criteria at the time you commence construction.

(d) A boiler is a new affected source if you commenced fuel switching from natural gas to solid fossil fuel, biomass, or liquid fuel after June 4, 2010.

(e) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or part 71 as a result of this subpart. You may, however, be required to obtain a title V permit due to another reason or reasons. *See* 40 CFR 70.3(a) and (b) or 71.3(a) and (b). Notwithstanding the exemption from title V permitting for area sources under this subpart, you must continue to comply with the provisions of this subpart.

§ 63.11195 Are any boilers not subject to this subpart?

The types of boilers listed in paragraphs (a) through (g) of this section are not subject to this subpart and to any requirements in this subpart.

(a) Any boiler specifically listed as, or included in the definition of, an affected source in another standard(s) under this part.

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

(c) 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).

(d) A boiler that is used specifically for research and development. This exemption does not include boilers that solely or primarily provide steam (or heat) to a process or for heating at a research and development facility. This exemption does not prohibit the use of the steam (or heat) generated from the boiler during research and development, however, the boiler must be concurrently and primarily engaged in research and development for the exemption to apply.

(e) A gas-fired boiler as defined in this subpart.

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

(g) Any boiler 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.

§ 63.11196 What are my compliance dates?

(a) If you own or operate an existing affected boiler, you must achieve compliance with the applicable provisions in this subpart as specified in paragraphs (a)(1) through (3) of this section.

(1) If the existing affected boiler is subject to a work practice or management practice standard of a tune-up, you must achieve compliance with the work practice or management standard no later than March 21, 2012.

(2) If the existing affected boiler is subject to emission limits, you must achieve compliance with the emission limits no later than March 21, 2014.

(3) If the existing affected boiler is subject to the energy assessment requirement, you must achieve compliance with the energy assessment requirement no later than March 21, 2014.

(b) If you start up a new affected source on or before May 20, 2011, you must achieve compliance with the provisions of this subpart no later than May 20, 2011.

(c) If you start up a new affected source after May 20, 2011, you must achieve compliance with the provisions of this subpart upon startup of your affected source.

(d) If you own or operate an industrial, commercial, or institutional boiler and would be subject to this subpart except for the exemption in § 63.11195(b) for commercial and industrial solid waste incineration units covered by 40 CFR 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 waste to fuel switch.

Emission Limits, Work Practice Standards, Emission Reduction Measures, and Management Practices

§ 63.11200 What are the subcategories of boilers?

The subcategories of boilers are coal, biomass, and oil. Each subcategory is defined in § 63.11237.

§ 63.11201 What standards must I meet?

(a) You must comply with each emission limit specified in Table 1 to this subpart that applies to your boiler.

(b) You must comply with each work practice standard, emission reduction measure, and management practice specified in Table 2 to this subpart that applies to your boiler. An energy assessment completed on or after January 1, 2008 that meets the requirements in Table 2 to this subpart satisfies the energy assessment portion of this requirement.

(c) You must comply with each operating limit specified in Table 3 to this subpart that applies to your boiler.

(d) These standards apply at all times.

General Compliance Requirements

§ 63.11205 What are my general requirements for complying with this subpart?

(a) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator 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) You can demonstrate compliance with any applicable mercury emission limit using fuel analysis if the emission rate calculated according to § 63.11211(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using stack testing.

(c) If you demonstrate compliance with any applicable emission limit through performance stack testing and subsequent compliance with operating limits (including the use of continuous parameter monitoring system), with a CEMS, or with a COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (3) 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 continuous monitoring system 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 (c)(1)(i) through (vi) 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 which meet the requirements of § 63.11224.

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

(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).

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

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

(vi) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 8 to this subpart), (e)(1), and (e)(2)(i).

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

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

Initial Compliance Requirements

§ 63.11210 What are my initial compliance requirements and by what date must I conduct them?

(a) You must demonstrate initial compliance with each emission limit specified in Table 1 to this subpart that applies to you by either conducting performance (stack) tests, as applicable, according to § 63.11212 and Table 4 to this subpart or, for mercury, conducting fuel analyses, as applicable, according to § 63.11213 and Table 5 to this subpart.

(b) For existing affected boilers that have applicable emission limits, you must demonstrate initial compliance no later than 180 days after the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2).

(c) For existing affected boilers that have applicable work practice standards, management practices, or emission reduction measures, you must demonstrate initial compliance no later than the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2).

(d) For new or reconstructed affected sources, you must demonstrate initial compliance no later than 180 calendar days after March 21, 2011 or within 180 calendar days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(e) For affected boilers that ceased burning solid waste consistent with § 63.11196(d), 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 before you commence or recommence combustion of solid waste.

§ 63.11211 How do I demonstrate initial compliance with the emission limits?

(a) For affected boilers that demonstrate compliance with any of the emission limits of this subpart through performance (stack) testing, your initial compliance requirements include conducting performance tests according to § 63.11212 and Table 4 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler according to § 63.11213 and Table 5 to this subpart, establishing operating limits according to § 63.11222, Table 6 to this subpart and paragraph (b) of this section, as applicable, and conducting continuous monitoring system (CMS) performance evaluations according to § 63.11224. For affected boilers 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. For purposes of this subpart, boilers that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected boilers that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.11213 and Table 5 to this subpart.

(b) You must establish parameter operating limits according to paragraphs (b)(1) through (4) of this section.

(1) For a wet scrubber, you must establish the minimum liquid flowrate and pressure drop as defined in § 63.11237, as your operating limits during the three-run performance stack test. If you use a wet scrubber and you conduct separate performance stack tests for particulate matter and mercury emissions, you must establish one set of minimum scrubber liquid flowrate and pressure drop operating limits. If you conduct multiple performance stack tests, you must set the minimum liquid flowrate and pressure drop operating limits at the highest minimum values established during the performance stack tests.

(2) For an electrostatic precipitator operated with a wet scrubber, you must establish the minimum voltage and secondary amperage (or total electric power input), as defined in § 63.11237, as your operating limits during the three-run performance stack test. (These operating limits do not apply to electrostatic precipitators that are operated as dry controls without a wet scrubber.)

(3) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.11237, as your operating limit during the three-run performance stack test.

(4) The operating limit for boilers 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 § 63.11224, 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 mercury emission limit through fuel analysis, you must conduct fuel analyses according to § 63.11213 and Table 5 to this subpart and follow the procedures in paragraphs (c)(1) through (3) of this section.

(1) If you burn more than one fuel type, you must determine the fuel type, or mixture, you could burn in your boiler that would result in the maximum emission rates of mercury.

(2) You must determine the 90th percentile confidence level fuel mercury concentration of the composite samples analyzed for each fuel type using Equation 1 of this section.

$$P_{90} = mean + (SD * t) \quad \text{(Eq. 1)}$$

Where:

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

mean = Arithmetic average of the fuel mercury concentration in the fuel samples analyzed according to § 63.11213, in units of pounds per million Btu.

SD = Standard deviation of the mercury concentration in the fuel samples analyzed according to § 63.11213, 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 mercury emission limit, the emission rate that you calculate for your boiler using Equation 1 of this section must be less than the applicable mercury emission limit.

§ 63.11212 What stack tests and procedures must I use for the performance tests?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(b) You must conduct each stack test according to the requirements in Table 4 to this subpart.

(c) You must conduct performance stack tests at the representative operating load conditions while burning the type of fuel or mixture of fuels that have the highest emissions potential for each regulated pollutant, and you must demonstrate initial compliance and establish your operating limits based on these performance stack tests. For subcategories with more than one emission limit, these requirements could result in the need to conduct more than one performance stack test. Following each performance stack test and until the next performance stack test, you must comply with the operating limit for operating load conditions specified in Table 3 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance stack test required in this section, as specified in § 63.7(e)(3) and in accordance with the provisions in Table 4 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 of appendix A–7 to part 60 of this chapter to convert the measured particulate matter concentrations and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates.

§ 63.11213 What fuel analyses and procedures must I use for the performance tests?

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) and (c) of this section and Table 5 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 in Table 1 of this subpart.

(b) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in Table 5 to this subpart. Each composite sample must consist of a minimum of three samples collected at approximately equal intervals during a test run period.

(c) Determine the concentration of mercury in the fuel in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 5 to this subpart.

§ 63.11214 How do I demonstrate initial compliance with the work practice standard, emission reduction measures, and management practice?

(a) If you own or operate an existing or new coal-fired boiler with a heat input capacity of less than 10 million Btu per hour, you must conduct a performance tune-up according to § 63.11223(b) and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the boiler.

(b) If you own or operate an existing or new biomass-fired boiler or an existing or new oil-fired boiler, you must conduct a performance tune-up according to § 63.11223(b) and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the boiler.

(c) If you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit a signed certification in the Notification of Compliance Status report that an energy assessment of the boiler and its energy use systems was completed and submit, upon request, the energy assessment report.

(d) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler'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 boiler of similar design if manufacturer's recommended procedures are not available.

Continuous Compliance Requirements

§ 63.11220 When must I conduct subsequent performance tests?

(a) If your boiler has a heat input capacity of 10 million Btu per hour or greater, you must conduct all applicable performance (stack) tests according to § 63.11212 on an triennial basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Triennial performance tests must be completed no more than 37 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.

(b) You can conduct performance stack tests less often for particulate matter or mercury if your performance stack tests for the pollutant for at least 3 consecutive years show that your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions. In this case, you do not have to conduct a performance stack test for that pollutant for the next 2 years. You must conduct a performance stack test during the third year and no more than 37 months after the previous performance stack test.

(c) If your boiler continues to meet the emission limit for particulate matter or mercury, you may choose to conduct performance stack tests for the pollutant every third year if your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions, but each such performance stack test must be conducted no more than 37 months after the previous performance test.

(d) If you have an applicable CO emission limit, you must conduct triennial performance tests for CO according to § 63.11212. Each triennial performance test must be conducted between no more than 37 months after the previous performance test.

(e) If you demonstrate compliance with the mercury emission limit based on fuel analysis, you must conduct a fuel analysis according to § 63.11213 for each type of fuel burned monthly. If you plan to burn a new type of fuel or fuel mixture, you must conduct a fuel analysis before burning the new type of fuel or mixture in your boiler. You must recalculate the mercury emission rate using Equation 1 of § 63.11211. The recalculated mercury emission rate must be less than the applicable emission limit.

§ 63.11221 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section.

(b) You must operate the monitoring system and collect data at all required intervals at all times the affected source is operating except for periods of monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods (see section 63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to 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 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.

§ 63.11222 How do I demonstrate continuous compliance with the emission limits?

(a) You must demonstrate continuous compliance with each emission limit and operating limit in Tables 1 and 3 to this subpart that applies to you according to the methods specified in Table 7 to this subpart and to paragraphs (a)(1) through (4) 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 63.11196, whichever date comes first, you must continuously monitor the operating parameters. Operation above the established maximum, below the established minimum, or outside the allowable range of the operating limits specified in paragraph (a) of this section constitutes a deviation from your operating limits established under this subpart, except during performance tests conducted to determine compliance with the emission and operating limits or to establish new operating limits. Operating limits are confirmed or reestablished during performance tests.

(2) If you have an applicable mercury or PM emission limit, you must keep records of the type and amount of all fuels burned in each boiler during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in lower emissions of mercury than the applicable emission limit (if you demonstrate compliance through fuel analysis), or result in lower fuel input of mercury than the maximum values calculated during the last performance stack test (if you demonstrate compliance through performance stack testing).

(3) If you have an applicable mercury emission limit and you plan to burn a new type of fuel, you must determine the mercury concentration for any new fuel type in units of pounds per million Btu, using the procedures in Equation 1 of § 63.11211 based on supplier data or your own fuel analysis, and meet the requirements in paragraphs (a)(3)(i) or (ii) of this section.

(i) The recalculated mercury emission rate must be less than the applicable emission limit.

(ii) If the mercury concentration is higher than mercury fuel input 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 § 63.11212 to demonstrate that the mercury emissions do not exceed the emission limit.

(4) 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 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 is counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time is counted as the actual amount of time taken to initiate corrective action.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 and 3 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 § 63.11225.

§ 63.11223 How do I demonstrate continuous compliance with the work practice and management practice standards?

(a) For affected sources subject to the work practice standard or the management practices of a tune-up, you must conduct a biennial performance tune-up according to paragraphs (b) of this section and keep records as required in § 63.11225(c) to demonstrate continuous compliance. Each biennial tune-up must be conducted no more than 25 months after the previous tune-up.

(b) You must conduct a tune-up of the boiler biennially to demonstrate continuous compliance as specified in paragraphs (b)(1) through (7) of this section.

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, but you must inspect each burner at least once every 36 months).

(2) 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.

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

(4) Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications, if available.

(5) 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).

(6) Maintain onsite and submit, if requested by the Administrator, biennial report containing the information in paragraphs (b)(6)(i) through (iii) of this section.

(i) The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured before and after the tune-up of the boiler.

(ii) A description of any corrective actions taken as a part of the tune-up of the boiler.

(iii) The type and amount of fuel used over the 12 months prior to the biennial tune-up of the boiler.

(7) 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.

(c) If you own or operate an existing or new coal-fired boiler with a heat input capacity of 10 million Btu per hour or greater, you must minimize the boiler's time spent during startup and shutdown following the manufacturer's recommended procedures and 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.

§ 63.11224 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler is subject to a carbon monoxide emission limit in Table 1 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 § 63.11196. The oxygen level shall be monitored at the outlet of the boiler.

(1) Each monitor 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 paragraph (c) of this section.

(2) You must conduct a performance evaluation of each CEMS according to the requirements in § 63.8(e) and according to Performance Specification 3 at 40 CFR part 60, appendix B.

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

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

(5) You must calculate and record the 12-hour block average concentrations.

(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 you are using a control device to comply with the emission limits specified in Table 1 to this subpart, you must maintain each operating limit in Table 3 to this subpart that applies to your boiler as specified in Table 7 to this subpart. If you use a control device not covered in Table 3 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under § 63.8(f).

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

(1) For each continuous monitoring system (CMS) required in this section, you must develop, and submit to the EPA Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (b)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan (if requested) at least 60 days before your initial performance evaluation of your CMS.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected 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.

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

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

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

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

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

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

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

(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.

(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 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) Determine the 12-hour block average of all recorded readings, except as provided in paragraph (d)(3) of this section.

(5) Record the results of each inspection, calibration, and validation check.

(e) If you have an applicable opacity operating limit under this rule, you must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (e)(1) through (7) of this section by the compliance date specified in § 63.11196.

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

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

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

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

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

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan

and the requirements of § 63.8(e). 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.

(7) You must determine and record all the 1-hour block averages collected for periods during which the COMS is not out of control.

(f) If you 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 (f)(1) through (8) of this section.

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

(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with EPA–454/R–98–015 (incorporated by reference, see § 63.14).

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

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

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

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

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

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

§ 63.11225 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications specified in paragraphs (a)(1) through (a)(5) of this section to the delegated authority.

(1) You must submit all of the notifications in §§ 63.7(b): 63.8(e) and (f); 63.9(b) through (e); and 63.9(g) and (h) that apply to you by the dates specified in those sections.

(2) As specified in § 63.9(b)(2), you must submit the Initial Notification no later than 120 calendar days after May 20, 2011 or within 120 days after the source becomes subject to the standard.

(3) If you are required to conduct a performance stack test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance stack test is scheduled to begin.

(4) You must submit the Notification of Compliance Status in accordance with § 63.9(h) no later than 120 days after the applicable compliance date specified in § 63.11196 unless you must conduct a performance stack test. If you must conduct a performance stack test, you must submit the Notification of Compliance Status within 60 days of completing the performance stack test. In addition to the information required in § 63.9(h)(2), your notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the requirements in § 63.11214 to conduct an initial tune-up of the boiler."

(ii) "This facility has had an energy assessment performed according to § 63.11214(c)."

(iii) For an owner or operator that installs bag leak detection systems: "This facility has prepared a bag leak detection system monitoring plan in accordance with § 63.11224 and will operate each bag leak detection system according to the plan."

(iv) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: "No secondary materials that are solid waste were combusted in any affected unit."

(5) If you are using data from a previously conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart consistent with § 63.7(e)(2)(iv), you must submit the test data in lieu of the initial performance test results with the Notification of Compliance Status required under paragraph (a)(4) of this section.

(b) You must prepare, by March 1 of each year, and submit to the delegated authority upon request, an annual compliance certification report for the previous calendar year containing the information specified in paragraphs (b)(1) through (4) of this section. You must submit the report by March 15 if you had any instance described by paragraph (b)(3) of this section. For boilers that are subject only to a requirement to conduct a biennial tune-up according to § 63.11223(a) and not subject to emission limits or operating limits, you may prepare only a biennial compliance report as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) Company name and address.

(2) Statement by a responsible official, with the official's name, title, phone number, e-mail address, and signature, certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of this subpart.

(3) If the source experiences any deviations from the applicable requirements during the reporting period, include a description of deviations, the time periods during which the deviations occurred, and the corrective actions taken.

(4) The total fuel use by each affected boiler subject to an emission limit, for each calendar month within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by you or EPA through a petition process to be a non-waste under § 241.3(c), whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of § 241.3, and the total fuel usage amount with units of measure.

(c) You must maintain the records specified in paragraphs (c)(1) through (5) of this section.

(1) As required in § 63.10(b)(2)(xiv), you must keep a copy of each notification and report that you submitted to comply with this subpart and all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted.

(2) You must keep records to document conformance with the work practices, emission reduction measures, and management practices required by § 63.11214 as specified in paragraphs (c)(2)(i) and (ii) of this section.

(i) Records must identify each boiler, the date of tune-up, the procedures followed for tune-up, and the manufacturer's specifications to which the boiler was tuned.

(ii) Records documenting the fuel type(s) used monthly by each boiler, including, but not limited to, a description of the fuel, including whether the fuel has received a non-waste determination by you or EPA, and the total fuel usage amount with units of measure. If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 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) For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation that were done to demonstrate compliance with the mercury emission limits. Supporting documentation should include results of any fuel analyses. You can use the results from one fuel analysis for multiple boilers provided they are all burning the same fuel type.

(4) Records of the occurrence and duration of each malfunction of the boiler, or of the associated air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.11205(a), including corrective actions to restore the malfunctioning boiler, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(6) You must keep the records of all inspection and monitoring data required by §§ 63.11221 and 63.11222, and the information identified in paragraphs (c)(6)(i) through (vi) of this section for each required inspection or monitoring.

(i) The date, place, and time of the monitoring event.

(ii) Person conducting the monitoring.

(iii) Technique or method used.

(iv) Operating conditions during the activity.

(v) Results, including the date, time, and duration of the period from the time the monitoring indicated a problem to the time that monitoring indicated proper operation.

(vi) Maintenance or corrective action taken (if applicable).

(7) If you use a bag leak detection system, you must keep the records specified in paragraphs (c)(7)(i) through (iii) of this section.

(i) Records of the bag leak detection system output.

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

(iii) The date and time of all bag leak detection system alarms, and for each valid alarm, the time you initiated corrective action, the corrective action taken, and the date on which corrective action was completed.

(d) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1). As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each recorded action. You must keep each record onsite for at least 2 years after the date of each recorded action according to § 63.10(b)(1). You may keep the records off site for the remaining 3 years.

(e) 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.

(f) 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) 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.

(g) If you intend to switch fuels, and this fuel switch may result in the applicability of a different subcategory or a switch out of subpart JJJJJJ due to a switch to 100 percent natural gas, 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.

§ 63.11226 How can I assert an affirmative defense if I exceed an emission limit during a malfunction?

In response to an action to enforce the standards set forth in paragraph § 63.11201 you may assert an affirmative defense to a claim for civil penalties for exceedances of numerical emission limits 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 limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.11201 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.

Other Requirements and Information

§ 63.11235 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.11236 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 has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if implementation and enforcement of 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 contained in paragraphs (c) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency.

(c) The authorities that cannot be delegated to state, local, or tribal agencies are specified in paragraphs (c)(1) through (5) of this section.

(1) Approval of an alternative non-opacity emission standard and work practice standards in § 63.11223(a).

(2) Approval of alternative opacity emission standard under § 63.6(h)(9).

(3) Approval of major change to test methods under § 63.7(e)(2)(ii) and (f). A "major change to test method" is defined in § 63.90.

(4) Approval of a major change to monitoring under § 63.8(f). A "major change to monitoring" is defined in § 63.90.

(5) Approval of major change to recordkeeping and reporting under § 63.10(f). A "major change to recordkeeping/reporting" is defined in § 63.90.

§ 63.11237 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 basis means the heat input for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that is capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.,* baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Biomass means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue and 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.

Biomass subcategory includes any boiler that burns at least 15 percent biomass on an annual heat input basis.

Boiler means an enclosed device using controlled flame combustion in which water is heated to recover 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. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feedwater system, the combustion air system, the boiler fuel system (including burners), blowdown system, combustion control system, steam system, and condensate return system.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in 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 including, but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal subcategory includes any boiler that burns any solid fossil fuel and no more than 15 percent biomass on an annual heat input basis.

Commercial boiler means a boiler used in commercial establishments such as hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

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;

(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; or

(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.

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 are included in this definition. A dry scrubber is a dry control system.

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 a dry control system, except when it is operated with a wet scrubber.

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 using less than 0.3 trillion Btu (TBtu) 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 affected boiler(s) energy output will be evaluated to identify energy savings opportunities, within the limit of performing a one day energy assessment.

(2) Energy assessment for facilities with affected boilers and process heaters using 0.3 to 1 TBtu/year will be three days in length maximum. The boiler system(s) and any energy use system(s) accounting for at least 33 percent of the affected boiler(s) energy output will be evaluated to identify energy savings opportunities, within the limit of performing a 3-day energy assessment.

(3) Energy assessment for facilities with affected boilers and process heaters using greater than 1.0 TBtu/year, the boiler system(s) and any energy use system(s) accounting for at least 20 percent of the affected boiler(s) energy output will be evaluated to identify energy savings opportunities.

Energy use system includes, but not limited to, process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning (HVAC) systems; hot heater systems;, building envelop; and lighting.

Equivalent means the following only as this term is used in Table 5 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 mercury using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing this metal. 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 mercury concentration mathematically adjusted to a dry basis.

(6) An equivalent mercury determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for mercury and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 5 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 part 60 and 40 CFR part 61, requirements within any applicable state implementation plan, and any permit requirements established under §§ 52.21 or under 51.18 and § 51.24.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuels includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, hydrogen, and biogas.

Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Heat input means heat derived from combustion of fuel in a boiler and does not include the heat input from preheated combustion air, recirculated flue gases, or returned condensate.

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).

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

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

Liquid fuel means, but not limited to, petroleum, distillate oil, residual oil, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, and biodiesel.

Minimum activated carbon injection rate means load fraction (percent) multiplied by the lowest 1-hour average activated carbon injection rate measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

Minimum oxygen level means the lowest 1-hour average oxygen level measured according to Table 6 of this subpart during the most recent performance stack test demonstrating compliance with the applicable CO emission limit.

Minimum PM scrubber pressure drop means the lowest 1-hour average PM scrubber pressure drop measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum sorbent flow rate means the boiler load (percent) multiplied by the lowest 2-hour average sorbent (or activated carbon) injection rate measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

Minimum voltage or amperage means the lowest 1-hour average total electric power value (secondary voltage × secondary current = secondary electric power) to the electrostatic precipitator measured according to Table 6 to this subpart during the most recent performance stack 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 including intermediate gas streams generated during processing of natural gas at production sites or at gas processing plants; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 63.14).

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

(4) Propane or propane-derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Oil subcategory includes any boiler that burns any liquid fuel and is not in either the biomass or coal subcategories. Gas-fired boilers that burn liquid fuel during periods of gas curtailment, gas supply emergencies, or for periodic testing not to exceed 48 hours during any calendar year are not included in this definition.

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

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 alternative method.

Performance testing means the collection of data resulting from the execution of a test method used (either by stack testing or fuel analysis) to demonstrate compliance with a relevant emission standard.

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.

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.

Responsible official means responsible official as defined in § 70.2.

Solid fossil fuel includes, but not limited to, coal, petroleum coke, and tire derived fuel.

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.

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

TABLE 1 TO SUBPART JJJJJJ OF PART 63—EMISSION LIMITS

[As stated in § 63.11201, you must comply with the following applicable emission limits:]

If your boiler is in this subcategory	For the following pollutants. . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown. . .
1. New coal-fired boiler with heat input capacity of 30 million Btu per hour or greater.	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Mercury	0.0000048 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen.
2. New coal-fired boiler with heat input capacity of between 10 and 30 million Btu per hour.	a. Particulate Matter	0.42 lb per MMBtu of heat input.

TABLE 1 TO SUBPART JJJJJJ OF PART 63—EMISSION LIMITS—Continued

[As stated in § 63.11201, you must comply with the following applicable emission limits:]

If your boiler is in this subcategory	For the following pollutants. . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown. . .
	b. Mercury	0.0000048 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen.
3. New biomass-fired boiler with heat input capacity of 30 million Btu per hour or greater.	a. Particulate Matter	0.03 lb per MMBtu of heat input.
4. New biomass fired boiler with heat input capacity of between 10 and 30 million Btu per hour.	a. Particulate Matter	0.07 lb per MMBtu of heat input.
5. New oil-fired boiler with heat input capacity of 10 million Btu per hour or greater.	a. Particulate Matter	0.03 lb per MMBtu of heat input.
6. Existing coal (units with heat input capacity of 10 million Btu per hour or greater).	a. Mercury	0.0000048 lb per MMBtu of heat input.
	b. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen.

TABLE 2 TO SUBPART JJJJJJ OF PART 63—WORK PRACTICE STANDARDS, EMISSION REDUCTION MEASURES, AND MANAGEMENT PRACTICES

[As stated in § 63.11201, you must comply with the following applicable work practice standards, emission reduction measures, and management practices:]

If your boiler is in this subcategory. . .	You must meet the following. . .
1. Existing or new coal, new biomass, and new oil (units with heat input capacity of 10 million Btu per hour or greater).	Minimize the boiler'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.
2. Existing or new coal (units with heat input capacity of less than 10 million Btu per hour).	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
3. Existing or new biomass or oil	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
4. Existing coal, biomass, or oil (units with heat input capacity of 10 million Btu per hour and greater).	Must have a one-time energy assessment performed by a 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: (1) A visual inspection of the boiler system, (2) An evaluation of operating characteristics of the facility, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints, (3) Inventory of major systems consuming energy from affected boiler(s), (4) A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage, (5) A list of major energy conservation measures, (6) A list of the energy savings potential of the energy conservation measures identified, (7) A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

TABLE 3 TO SUBPART JJJJJJ OF PART 63—OPERATING LIMITS FOR BOILERS WITH EMISSION LIMITS

[As stated in § 63.11201, you must comply with the applicable operating limits:]

If you demonstrate compliance with applicable emission limits using . . .	You must meet these operating limits. . .
1. Fabric filter control	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 § 63.11224 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.
2. Electrostatic precipitator control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Maintain the secondary power input of the electrostatic precipitator at or above the lowest 1-hour average secondary electric power measured during the most recent performance test demonstrating compliance with the particulate matter emission limitations.
3. Wet PM scrubber control	Maintain the pressure drop at or above the lowest 1-hour average pressure drop across the wet scrubber and the liquid flow-rate at or above the lowest 1-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the PM emission limitation.

TABLE 3 TO SUBPART JJJJJJ OF PART 63—OPERATING LIMITS FOR BOILERS WITH EMISSION LIMITS—Continued

[As stated in § 63.11201, you must comply with the applicable operating limits:]

If you demonstrate compliance with applicable emission limits using . . .	You must meet these operating limits. . .
4. Dry sorbent or carbon injection control	Maintain the sorbent or carbon injection rate at or above the lowest 2-hour average sorbent flow rate measured during the most recent performance test demonstrating compliance with the mercury emissions limitation. When your boiler operates at lower loads, multiply your sorbent or carbon injection rate by the load fraction (e.g., actual heat input divided by the heat input during performance stack test, for 50 percent load, multiply the injection rate operating limit by 0.5).
5. Any other add-on air pollution control type	This option is for boilers that operate dry control systems. Boilers must maintain opacity to less than or equal to 10 percent opacity (daily block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture (annual average) such that the mercury emission rates calculated according to § 63.11211(b) is less than the applicable emission limits for mercury.
7. Performance stack testing	For boilers that demonstrate compliance with a performance stack test, maintain the operating load of each unit such that is does not exceed 110 percent of the average operating load recorded during the most recent performance stack test.
8. Continuous Oxygen Monitor	Maintain the oxygen level at or above the lowest 1-hour average oxygen level measured during the most recent CO performance stack test.

TABLE 4 TO SUBPART JJJJJJ OF PART 63—PERFORMANCE (STACK) TESTING REQUIREMENTS

[As stated in § 63.11212, you must comply with the following requirements for performance (stack) test for affected sources:]

To conduct a performance test for the following pollutant. . .	You must. . .	Using. . .
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A–1 to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A–2 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A–2 to part 60 of this chapter, or ASTM D6522–00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A–3 to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A–3 and A–6 to part 60 of this chapter and a minimum 1 dscm of sample volume per run.
	f. Convert emissions concentration to lb/MMBtu emission rates.	Method 19 F-factor methodology in appendix A–7 to part 60 of this chapter.
2. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A–1 to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A–2 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A–2 to part 60 of this chapter, or ASTM D6522–00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A–3 to part 60 of this chapter.
	e. Measure the mercury emission concentration.	Method 29, 30A, or 30B in appendix A–8 to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784–02.[a] Collect a minimum 2 dscm of sample volume with Method 29 of 101A per run. Use a minimum run time of 2 hours with Method 30A.
	f. Convert emissions concentration to lb/MMBtu emission rates.	Method 19 F-factor methodology in appendix A–7 to part 60 of this chapter.
3. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points.	Method 1 in appendix A–1 to part 60 of this chapter.
	b. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A–2 to part 60 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 in appendix A–3 to part 60 of this chapter.

TABLE 4 TO SUBPART JJJJJJ OF PART 63—PERFORMANCE (STACK) TESTING REQUIREMENTS—Continued

[As stated in § 63.11212, you must comply with the following requirements for performance (stack) test for affected sources:]

To conduct a performance test for the following pollutant. . .	You must. . .	Using. . .
	d. Measure the carbon monoxide emission concentration.	Method 10, 10A, or 10B in appendix A–4 to part 60 of this chapter or ASTM D6522–00 (Reapproved 2005) [a] and a minimum 1 hour sampling time per run.

[a] Incorporated by reference, see § 63.14.

TABLE 5 TO SUBPART JJJJJJ OF PART 63—FUEL ANALYSIS REQUIREMENTS

[As stated in § 63.11213, you must comply with the following requirements for fuel analysis testing for affected sources:]

To conduct a fuel analysis for the following pollutant . . .	You must. . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.11213(b) or ASTM D2234/D2234M [a] (for coal) or ASTM D6323 [a] (for biomass) or equivalent.
	b. Compose fuel samples	Procedure in § 63.11213(b) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B [a] (for solid samples) or EPA SW–846–3020A [a] (for liquid samples) or 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 mercury concentration in fuel sample	ASTM D6722 [a] (for coal) or EPA SW–846–7471B [a] (for solid samples) or EPA SW–846–7470A [a] (for liquid samples) or equivalent.
	g. Convert concentrations into units of lb/MMBtu of heat content	

[a] Incorporated by reference, see § 63.14.

TABLE 6 TO SUBPART JJJJJJ OF PART 63—ESTABLISHING OPERATING LIMITS

[As stated in § 63.11211, you must comply with the following requirements for 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 § 63.11211(b).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter or mercury performance stack test.	(a) You must collect pressure drop and liquid flow-rate data every 15 minutes during the entire period of the performance stack tests;
	(b) Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run..			
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).	i. Establish a site-specific minimum secondary electric power according to § 63.11211(b).	(1) Data from the secondary electric power monitors during the particulate matter or mercury performance stack test.	(a) You must collect secondary electric power input data every 15 minutes during the entire period of the performance stack tests; (b) Determine the secondary electric power input for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.

TABLE 6 TO SUBPART JJJJJJ OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

[As stated in § 63.11211, you must comply with the following requirements for 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
2. Mercury	a. Activated carbon injection.	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.11211(b).	(1) Data from the activated carbon rate monitors and mercury performance stack tests.	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average activated carbon injection rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run. (c) 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 stack test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.11211(b).	(1) Data from the oxygen monitor specified in § 63.11224(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average oxygen concentration for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.

TABLE 7 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

[As stated in § 63.11222, you must show continuous compliance with the emission limitations for affected sources according to the following:]

If you must meet the following operating limits. . .	You must demonstrate continuous compliance by. . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.11224(e) and § 63.11221; 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 § 63.11224 and operating the fabric filter such that the requirements in § 63.11222(a)(4) 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 §§ 63.11224 and 63.11221; 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 § 63.1140.
4. Dry scrubber sorbent or carbon injection rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.11224 and 63.11220; 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 § 63.11237.
5. Electrostatic precipitator secondary amperage and voltage, or total power input.	a. Collecting the secondary amperage and voltage, or total power input monitoring system data for the electrostatic precipitator according to §§ 63.11224 and 63.11220; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average secondary amperage and voltage, or total power input at or above the operating limits established during the performance test according to § 63.11214.
6. Fuel pollutant content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.11214 as applicable; and b. Keeping monthly records of fuel use according to § 63.11222.
7. Oxygen content	a. Continuously monitor the oxygen content in the combustion exhaust according to § 63.11224. b. Maintain the 12-hour average oxygen content at or above the operating limit established during the most recent carbon monoxide performance test.

TABLE 8 TO SUBPART JJJJJJ OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART JJJJJJ

[As stated in § 63.11235, you must comply with the applicable General Provisions according to the following:]

General provisions cite	Subject	Does it apply?
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.11237.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	No
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c), (f)(2)–(3), (g), (i), (j)	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. *See* § 63.11205 for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP.	No.
§ 63.6(e)(3)	SSM Plan	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.6(h)(2) to (9)	Determining compliance with opacity emission standards.	Yes.
§ 63.7(a), (b), (c), (d) , (e)(2)–(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Performance testing	No. *See* § 63.11210.
§ 63.8(a), (b), (c)(1), (c)(1)(ii), (c)(2) to (c)(9), (d)(1) and (d)(2), (e),(f), and (g).	Monitoring Requirements	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS.	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a) and (b)(1)	Recordkeeping and Reporting Requirements.	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. *See* § 63.11225 for recordkeeping of (1) occurrence and duration and (2) 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 SSM.	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)	Recording nature and cause of malfunctions.	No. *See* § 63.11225 for malfunction recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. *See* § 63.11225 for malfunction recordkeeping requirements.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Allows use of SSM 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)	SSM reports	No. *See* § 63.11225 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.

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