ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2002–0058; FRL–9503–6]

RIN 2060–AR13

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule; Reconsideration of final rule.

SUMMARY: On March 21, 2011, the EPA promulgated national emission standards for the control of hazardous air pollutants from new and existing industrial, commercial, and institutional boilers and process heaters at major sources of hazardous air pollutants. On that same day, the EPA also published a notice announcing its intent to reconsider certain provisions of the final rule. The EPA subsequently issued a notice on May 18, 2011, to postpone the effective dates of the final rule until judicial review has been completed, or the agency finalizes its reconsideration of the standard, whichever is earlier. In the action to postpone the effective dates of the rule, the EPA also requested the public to submit data and information to assist the EPA in its reconsideration. Following these actions, the Administrator received several petitions for reconsideration. In response to the March 21, 2011, notice announcing its intent to initiate reconsideration and the petitions submitted, the EPA is reconsidering and requesting comment on several provisions of the final rule. Additionally, the EPA is proposing amendments and technical corrections to the final rule to clarify definitions, references, applicability, and compliance issues raised by stakeholders subject to the final rule.

DATES: *Comments.* Comments must be received on or before February 21, 2012.

Public Hearing. We will hold a public hearing concerning the proposed items for reconsideration. Persons interested in presenting oral testimony at the hearing should contact Ms. Teresa Clemons at (919) 541–7689 or at *clemons.teresa@epa.gov* by January 3, 2012. If no one requests to speak at the public hearing by January 3, 2012, then the public hearing will be cancelled. We will specify the date and time of the public hearings on *http://www.epa.gov/ttn/atw/boiler/boilerpg.html.*

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2002–0058, by one of the following methods:

- *http://www.regulations.gov:* Follow the instructions for submitting comments.
- *Email:* Comments may be sent by email to *a-and-r-Docket@epa.gov,* Attention Docket ID No. EPA–HQ–OAR–2002–0058.
- *Fax:* Fax your comments to: (202) 566–9744, Attention Docket ID No. EPA–HQ–OAR–2002–0058.
- *Mail:* Send your comments to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave. NW., Washington, DC 20460, Docket ID No. EPA–HQ–OAR–2002–0058. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, OMB, Attn: Desk Officer for EPA, 725 17th St. NW., Washington, DC 20503.
- *Hand Delivery:* In person or by courier, deliver comments to: EPA Docket Center (2822T), EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays), and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2002–0058. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *http://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

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

FOR FURTHER INFORMATION CONTACT: Mr. Brian Shrager, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–7689; Fax number: (919) 541–5450; Email address: *shrager.brian@epa.gov.*

SUPPLEMENTARY INFORMATION:

Organization of this Document. The following outline is provided to aid in locating information in this preamble.

I. General Information

A. Does this notice of reconsideration apply to me?

The regulated categories and entities potentially affected by this action include:

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

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this reconsideration action. To determine whether your facility may be affected by this reconsideration action, you should examine the applicability criteria in 40 CFR 63.7485 of subpart DDDDD (National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters). If you have any questions regarding the applicability of the proposed rule to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative, as listed in 40 CFR 63.13 of subpart A (General Provisions).

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

Submitting CBI. Do not submit information that you consider to be CBI electronically through *http://www.regulations.gov* or email. Send or deliver information identified as CBI to only the following address: Mr. Robert Morales, c/o OAQPS Document Control Officer (Room C404–02), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attn: Docket ID No. EPA–HQ–OAR–2002–0058.

Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. If you submit a disk or CD–ROM that does not contain CBI, mark the outside of the disk or CD–ROM clearly that it does not contain CBI. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

If you have any questions about CBI or the procedures for claiming CBI, please consult the person identified in the **FOR FURTHER INFORMATION CONTACT** section.

C. How do I obtain a copy of this document and other related information?

Docket. The docket number for this action and the proposed rule (40 CFR part 63, subpart DDDDD) is Docket ID No. EPA–HQ–OAR–2002–0058.

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

II. Background Information

On March 21, 2011, the EPA issued final standards for new and existing industrial, commercial, and institutional boilers and process heaters, pursuant to its authority under section 112 of the Clean Air Act (CAA). On the same day as this final rule was issued, EPA also stated in a separate notice that it planned to initiate a reconsideration of several provisions of the final rule. This reconsideration notice identified several provisions of the final rule where additional public comment was appropriate, including:

- Revisions to the proposed subcategories.
- Establishing a fuel specification through which gas-fired boilers that use a fuel other than natural gas or refinery gas may be considered Gas 1 units.
- Establishing a work practice standard for limited use units.
- Providing an affirmative defense for malfunction events.

This notice also identified several issues of central relevance to the rulemaking where reconsideration was appropriate under CAA section 307(d), including:

- Revisions to the proposed monitoring requirements for carbon monoxide for major source boilers.
- Revisions to the proposed dioxin emission limit and testing requirement for major source boilers.
- Establishing a full-load stack test requirement for carbon monoxide coupled with continuous oxygen (oxygen trim) monitoring.

On May 18, 2011, the EPA issued a notice to postpone the effective dates of the March 21, 2011, final rule. This notice also requested that the public submit additional data and information to the EPA by July 15, 2011, for review and consideration in the reconsideration proceedings. Following promulgation of the final rule, the EPA received petitions for reconsideration from the following organizations (''Petitioners''): Alliance for Industrial Efficiency (AIE), U.S. Clean Heat Power Association (USCHPA), Alyeska Pipeline, American Chemistry Council (ACC), American Home Furnishings Alliance (AHFA), American Iron and Steel Institute (AISI), American Coke and Coal Chemicals Institute (ACCCI), American Municipal Power Inc. (AMP), American Petroleum Institute (API), National Petrochemical and Refiners Association (NPRA), Auto Industry Forum (AIF), Citizens Energy Group (CEG), Council of Industrial Boiler Owners (CIBO), CraftMaster Manufacturing Inc. (CMI), District Energy St. Paul, Florida Sugar Industry (FSI), Great Plains Synfuels (GPSP), Hovensa L.L.C., Tesoro Hawaii Corp., Industry Coalition (AF&PA et. al.), JELD–WEN Inc., Michigan State University (MSU), Penn State University (PSU), Purdue University, Renovar Energy Corp., Rochester Public Utilities (RPU), Sierra Club, Southeastern Lumber Manufacturers Association, State of Washington Department of Ecology, The Business Council for Sustainable Energy (BCSE), Utility Air Regulatory Group (UARG), United States Sugar Corporation (U.S. Sugar), Waste Management Inc. (WM), and Wisconsin Electric Power Company. Copies of these petitions are provided in the docket (see Docket ID No. EPA–HQ–OAR–2002–0058). Petitioners, pursuant to CAA section 307(d)(7)(B), requested that the EPA reconsider numerous provisions in the rules. In this action, the EPA is proposing multiple changes to the final rule in response to the reconsideration requests and the issues that the EPA previously identified as reconsideration issues. The EPA also is soliciting comment on several provisions of the final rule for which we are not proposing changes, because the public did not previously have an opportunity to comment on those provisions. The issues upon which the EPA is soliciting comment are discussed in section V of this preamble.

III. Summary of This Proposed Rule

This section summarizes the requirements of this action. Some of the requirements are currently found in the final boilers rule and are not being proposed to be revised. Section IV below provides a summary of the significant changes the EPA is proposing to make in its reconsideration of the final rule, and on which EPA is soliciting public comment.

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

This proposed rule regulates industrial, commercial, and institutional boilers and process heaters located at major sources of hazardous air pollutants (HAP). Waste heat boilers and process heaters and boilers and process heaters that combust solid waste, except for specific exceptions to the definition of a solid waste incineration unit outlined in section 129(g)(1), are not subject to this proposed rule.

B. What is the affected source?

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

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

This proposed rule regulates hydrogen chloride (HCl) (as a surrogate for acid gas HAP), total selected metals (TSM) or particulate matter (PM) (as a surrogate for non-mercury HAP metals), carbon monoxide (CO) (as a surrogate for non-dioxin/furan organic HAP), mercury (Hg), and dioxin/furan emissions from boilers and process heaters.

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

You must meet the emission limits presented in Table 1 of this preamble for each subcategory of units listed in the table. This proposed rule includes 17 subcategories, which are based on unit design. New and existing units in 3 of the subcategories would be subject to work practices standards in lieu of emission limits for all pollutants. Numeric emission limits are being proposed for new and existing sources in each of 14 subcategories, which are shown in Table 1 of this preamble.

HCl and Hg are ''fuel-based pollutants'' that directly result from contaminants in the fuels that are combusted. For those pollutants, if your new or existing unit combusts at least 10 percent solid fuel on an annual basis, your unit is subject to emission limits that are based on data from all of the solid fuel-fired combustor designs. If your new or existing unit combusts liquid fuel (except as noted in this proposed rule) and less than 10 percent solid fuel and your facility is located in the continental United States, your unit is subject to the liquid fuel emission limits for the fuel-based pollutants. If your facility is located outside the lower contiguous 48 states and Alaska (referred to as a non-continental unit for the remainder of this preamble and in this proposed rule), and your new or existing unit combusts liquid fuel (except as noted in this rule) and less than 10 percent solid fuel, your unit is subject to the non-continental liquid fuel emission limits for the fuel-based pollutants. Finally, for the fuel-based pollutants, if your unit combusts gaseous fuel that does not qualify as a ''Gas 1'' fuel, your unit is subject to the Gas 2 emission limits in Table 1 of this preamble. If your unit is a metal process furnace, limited-use unit, or Gas 1 unit (that is, it combusts only natural gas, refinery gas, or other clean gas that meets the fuel specification, with limited exceptions for gas curtailments and emergencies), your unit is subject to a work practice standard that requires an annual tune-up in lieu of emission limits.

For the combustion-based pollutants, PM (a surrogate for metallic HAP) and CO (a surrogate for non-dioxin organic HAP), your unit is subject to the emission limits for the design-based subcategories shown in Table 1 of this preamble. We also are proposing, as alternatives to the PM limits, total selected metals emission limits for subcategories of units that combust solid fuels or Gas 2 fuels. If your new or existing boiler or process heater burns at least 10 percent biomass on an annual average heat input [1] basis, the unit is in one of the biomass subcategories. If your new or existing boiler or process heater burns at least 10 percent coal, on an annual average heat input basis, and less than 10 percent biomass, on an annual average heat input basis, the unit is in one of the coal subcategories. If your facility is located in the lower contiguous 48 states or Alaska and your new or existing boiler or process heater burns light liquid fuel (*i.e.,* distillate oil, biodiesel, or vegetable oil) and less than 10 percent coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the light liquid subcategory. If your facility is located in the lower contiguous 48 states or Alaska and your new or existing boiler or process heater burns heavy liquid fuel (other liquids that are not defined as light liquids) and less than 10 percent coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the heavy liquid subcategory. If your non-continental new or existing boiler or process heater burns liquid fuel and less than 10 percent coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the non-continental liquid subcategory. Finally, for combustion-based pollutants, if your unit combusts gaseous fuel that does not qualify as a ''Gas 1'' fuel, your unit is subject to the Gas 2 emission limits in Table 1. If your unit combusts only natural gas, refinery gas, or equivalent fuel (other gas that qualifies as Gas 1 fuel), with limited exceptions for gas curtailment and emergencies, your unit is subject to a work practice standard that requires an annual tune-up in lieu of emission limits.

TABLE 1—EMISSION LIMITS FOR BOILERS AND PROCESS HEATERS

[lb/MMBtu heat input basis unless noted; alternative output based limits are not shown in the summary table below]

Subcategory	Filterable Particulate Matter (Filterable PM) (or total selected metals) (lb per MMBtu of heat input) [a]	Hydrogen chloride (HCl) (lb per MMBtu of heat input) [a]	Mercury (Hg) (lb per MMBtu of heat input) [a]	Carbon monoxide(CO) (ppm @3% oxygen) [a]	Alternate CO CEMS limit, (ppm @3% oxygen) [b]
Existing—Solid fuel	NA	0.022	3.1E–06	NA	NA
Existing—Coal Stoker	0.028 (8.3E–05)	NA	NA	220	34
Existing—Coal Fluidized Bed	0.088 (1.7E–05)	NA	NA	56	59
Existing—Coal-Burning Pulverized Coal	0.044 (5.9E–05)	NA	NA	41	28
Existing—Biomass Wet Stoker/Sloped Grate/Other	0.029 (5.7E–05)	NA	NA	790	410
Existing—Biomass Kiln-Dried Stoker/Sloped Grate/Other	0.32 (0.004)	NA	NA	250	ND
Existing—Biomass Fluidized Bed	0.11 (0.0012)	NA	NA	370	180
Existing—Biomass Suspension Burner	0.051 (0.0011)	NA	NA	58	1,400
Existing—Biomass Dutch Ovens/Pile Burners	0.036 (2.4E–04)	NA	NA	810	440
Existing—Biomass Fuel Cells	0.033 (4.9E–05)	NA	NA	1,500	ND
Existing—Biomass Hybrid Suspension Grate	0.44 (4.9E–04)	NA	NA	3,900	730
Existing—Liquid	NA	0.0012	2.6E–05	NA	NA
Existing—Heavy Liquid	[c] 0.062	NA	NA	10	18
Existing—Light Liquid	[c] 0.0034	NA	NA	7	[d] 60
Existing—non-Continental Liquid	[c] 0.0080	NA	NA	18	[e] 91
Existing—Gas 2 (Other Process Gases)	0.0067 (2.4E–04)	0.0017	7.9E–06	4	ND
New—Solid Fuel	NA	0.022	8.6E–07	NA	NA
New—Coal Stoker	0.028 (2.2E–05)	NA	NA	19	34
New—Coal Fluidized Bed	0.0011 (1.7E–05)	NA	NA	17	59
New—Coal-Burning Pulverized Coal	0.0013 (2.8E–05)	NA	NA	9	28
New—Biomass Wet Stoker/Sloped Grate/Other	0.029 (2.6E–05)	NA	NA	590	410
New—Biomass Kiln-Dried Stoker/Sloped Grate/Other	0.32 (0.0040)	NA	NA	250	ND
New—Biomass Fluidized Bed	0.0098 (4.2E–05)	NA	NA	230	180
New—Biomass Suspension Burner	0.051 (0.0011)	NA	NA	58	1,400
New—Biomass Dutch Ovens/Pile Burners	0.036 (4.1E–05)	NA	NA	810	440
New—Biomass Fuel Cells	0.011 (4.9E–05)	NA	NA	210	ND
New—Biomass Hybrid Suspension Grate	0.026 (4.9E–04)	NA	NA	1,500	730
New—Liquid	NA	0.0012	4.9E–07	NA	NA
New—Heavy Liquid	[c] 0.013	NA	NA	10	18
New—Light Liquid	[c] 0.0011	NA	NA	3	[d] 60
New—Non-Continental Liquid	[c] 0.0080	NA	NA	18	[e] 91
New—Gas 2 (Other Process Gases)	0.0067 (2.4E–04)	0.0017	7.9E–06	4	ND

NA—Not applicable; ND—No data available.
[a] 3-run average, unless otherwise noted.
[b] 10-day rolling average, unless otherwise noted.
[c] Total selected metals alternative limits are not available to units in any of the liquid subcategories.
[d] 1-day block average.

[1] Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

[e] 3-hour rolling average.

The emission limits in Table 1 apply only to new and existing boilers and process heaters that have a designed heat input capacity of 10 million British thermal units per hour (MMBtu/hr) or greater. We also are providing optional output-based standards in this proposed rule. Pursuant to CAA section 112(h), the final rule requires a work practice standard for the following particular classes of boilers and process heaters: new and existing units that have a designed heat input capacity of less than 10 MMBtu/hr, new and existing units in the Gas 1 (natural gas/refinery gas) subcategory and in the metal process furnaces subcategory, and new and existing limited-use units. The work practice standard for these boilers and process heaters requires the implementation of a tune-up program. We also are proposing a work practice standard for dioxin/furan emissions from all subcategories. Finally, the final rule includes a beyond-the-floor standard for all existing major source facilities having affected boilers or process heaters that would require the performance of a one-time energy assessment, as described in section IV of this preamble, of the affected boilers and facility to identify any cost-effective energy conservation measures.

E. What are the requirements during periods of startup, shutdown, and malfunction?

We are not proposing to change the malfunction provisions in this rule. *See* 76 FR 15613. We are proposing revised work practice standards for periods of startup and shutdown. The final rule required that an owner/operator must ''Minimize the unit's startup and shutdown periods following the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.''

While we are maintaining a work practice approach for startup and shutdown, we are proposing to change the work practice standards to better reflect the maximum achievable control technology. First, we are proposing definitions of startup and shutdown. We are proposing to define startup as the period between the state of no combustion in the unit to the period where the unit first achieves 25 percent load (*i.e.,* a cold start). We are proposing to define shutdown as the period that begins when a unit last operates at 25 percent load and ending with a state of no fuel combustion in the unit. For periods of startup and shutdown, we are proposing the following work practice standard: you must employ good combustion practices and demonstrate that good combustion practices are maintained by monitoring O_2 concentrations and optimizing those concentrations as specified by the boiler manufacturer; you must ensure that boiler operators are trained in startup and shutdown procedures, including maintenance and cleaning, safety, control device startup, and procedures to minimize emissions; and you must maintain records during periods of startup and shutdown and include in your compliance reports the O_2 conditions/data for each startup event, length of startup/shutdown and reason for the startup/shutdown (*i.e.,* normal/routine, problem/malfunction, outage). You must comply with all applicable emissions limits at all times except for startup and shutdown periods, during which times you must comply with these work practices.

F. What are the testing and initial compliance requirements?

We are requiring that the owner or operator of a new or existing boiler or process heater conduct performance tests to demonstrate compliance with all applicable emission limits. An owner or operator of any affected unit would be required to conduct the following compliance tests as applicable:

(1) Conduct initial and annual stack tests to determine compliance with the PM emission limits using EPA Method 5 or 17 or conduct initial and annual stack tests to determine compliance with the TSM emission limits using EPA Method 29 for those subcategories with alternate TSM limits.

(2) Conduct initial and annual stack tests to determine compliance with the Hg emission limits using EPA Method 29, 30B, or ASTM–D6784–02 (Ontario Hydro Method).

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

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

(5) Conduct initial and annual tests to determine compliance with the CO emission limits using EPA Method 10 or install, operate, and maintain CO continuous emission monitoring systems (CEMS) to determine compliance with the alternate CO CEMS-based emission limits.

As part of the initial compliance demonstration, we are requiring that you monitor specified operating parameters during the initial performance tests that you would conduct to demonstrate compliance with the PM or TSM (as appropriate), Hg, HCl, and CO emission limits. You must calculate the average hourly parameter values measured during each test run over the three-run performance test. The lowest or highest hourly parameter average measured during the three test runs (depending on the parameter measured) for each applicable parameter would establish the site-specific operating limit. The applicable operating parameters for which operating limits would be required to be established are based on the emissions limits applicable to your unit as well as the types of add-on controls on the unit. The following is a summary of the operating limits that we are requiring to be established for the various types of the following units:

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

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

(3) For boilers and process heaters with sorbent injection, you must measure the sorbent injection rate for each acid gas sorbent used during the performance tests for HCl and for activated carbon for Hg and calculate the hourly average for each sorbent injection rate during each test run. The lowest hourly average measured during the performance tests becomes your site-specific minimum sorbent injection rate operating limit. If different acid gas sorbents and/or injection rates are used during the HCl test, the lowest hourly

average value for each sorbent becomes your site-specific operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (operating heat input divided by the average heat input during your last compliance test for the appropriate pollutant) to determine the required injection rate operating limit value.

(4) For boilers and process heaters with fabric filters not subject to PM Continuous Parametric Monitoring System (PM CPMS) or continuous compliance with an opacity limit (*i.e.,* continuous opacity monitoring systems (COMS)), you must operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during any 6-month period unless a PM CPMS is installed to monitor PM control. For the purposes of the rule, we define a PM CPMS as a continuous parametric monitoring device based on a detection principle of light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample, installed and operated on the effluent stack or duct downstream of any particulate control device(s), and programmed to provide a continuous electronic signal representative of ongoing particulate matter control device performance.

(5) For boilers and process heaters with electrostatic precipitators (ESP) not subject to PM CPMS or continuous compliance with an opacity limit (*i.e.,* COMS), you must measure the secondary voltage and secondary current of the ESP collection fields during the Hg and PM performance test. You then calculate the average total secondary electric power value from these parameters for each test run. The lowest hourly average total secondary electric power measured during the three test runs establishes your site-specific minimum operating limit for the ESP on a 12-hour block average basis.

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

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

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

(9) For boilers and process heaters that are subject to a CO emission limit, you must record the oxygen concentration representative of your boiler operation (*e.g.,* oxygen trim) during the initial performance test.

These operating limits do not apply to owners or operators of boilers or process heaters having a heat input capacity of less than 10 MMBtu/hr or boilers or process heaters of any size which combust natural gas or other clean gas, metal process furnaces, or limited-use units. Instead, if requested, owners or operators of such boilers and process heaters shall submit to the delegated authority or the EPA, as appropriate, documentation that a tune-up meeting the requirements of this final rule was conducted. In order to comply with the work practice standard, a tune-up procedure must include the following actions:

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

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

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

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

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

(6) Submit to the delegated authority or the EPA an annual report containing the concentrations of CO in the effluent stream in ppmvd and oxygen in percent dry basis, both measured before and after the adjustments of the unit; a description of any corrective actions taken as a part of the combustion adjustment; and the type and amount of fuel used over the 12 months prior to the adjustment.

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

G. What are the continuous compliance requirements?

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

(1) For units combusting coal or residual fuel oil (*i.e.,* No. 4, 5 or 6 fuel oil) with average annual heat input rate of less than 250 MMBtu/hr (from the combustion of those fuels) or any units in the biomass subcategories and all biomass units that do not use a wet scrubber, opacity levels must be maintained to less than 10 percent (daily average) for existing and new units with applicable emission limits. If the unit is controlled with a fabric filter, instead of being subject to continuous opacity monitoring, the fabric filter must be continuously operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during any 6-month period (unless a PM CPMS is used).

(2) For units combusting coal or residual oil with heat input capacities of 250 MMBtu/hr or greater from the combustion of those fuels, the EPA is proposing the collection of data using a PM CPMS at all times that the unit is subject to numeric emission limits, with the exception of periods of PM CPMS repair, malfunction, scheduled maintenance, or QA/QC related activities. The operating unit will prepare, and submit for approval, a site-specific monitoring plan that addresses the PM CPMS design, data collection, and the QA/QC elements outlined in 63.8(d), including the performance criteria and design specifications for the monitoring system equipment, the sample interface location, frequency of quality control checks, frequency of system performance evaluations, ongoing operation and maintenance procedures as well as ongoing reporting and recordkeeping procedures. An annual deviation report must be submitted detailing data collected during periods of boiler startup, shutdown or malfunction and PM CPMS malfunction, repair, or other QA/QC related activity. Records of these data must be available on site for inspection, including corrective actions necessary to return the PM CPMS to operation consistent with the site specific monitoring plan. The operating unit will use output data collected from the CPMS (milliamps, milligrams per actual cubic meter, or other instrument output)

during all other operating hours where numeric emission limits apply to assess compliance with the operating limit. An arithmetic average of the measurement output values collected during each hour will be calculated, and for each operating day the arithmetic average of all hourly measurement output values will be calculated for the previous 30 operating days. You must transmit four reports per year for each PM CPMS to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface, or CEDRI, that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Complete reports must be submitted within 60 days after March 31st, June 30th, September 30th, and December 31st. Complete reports contain daily PM CPMS rolling 30-day average values for the periods that end with each of the 4 previously mentioned dates.

(3) For boilers and process heaters with wet PM scrubbers, you must monitor pressure drop and liquid flow rate of the scrubber and maintain the 30-day rolling averages at or above the operating limits established during the performance test to demonstrate continuous compliance with the PM emission limits.

(4) For boilers and process heaters with wet acid gas scrubbers, you must monitor the pH and liquid flow rate of the scrubber and maintain the 30-day rolling average at or above the operating limits established during the most recent performance test to demonstrate continuous compliance with the HCl emission limits.

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

(6) For boilers and process heaters not required to install a CPMS and having an ESP installed, you must monitor the voltage and current of the ESP collection plates and maintain the 30-day rolling average total secondary electric power at or above the operating limits established during the Hg, PM, or TSM performance test.

(7) For units that choose to comply with either the Hg emission limit, the HCl emission limit, or TSM emission limit (solid fuel units only) based on fuel analysis rather than on performance testing, you must maintain monthly fuel records that demonstrate that you burned no new fuels or fuels from a new supplier such that the Hg content, chlorine content, or TSM content of the inlet fuel was maintained at or below your maximum fuel Hg content operating limit, your chlorine content operating limit, or your TSM content operating limit set during the performance tests. If you plan to burn a new fuel, a fuel from a new mixture, or a new supplier's fuel that differs from what was burned during the initial performance tests, then you must recalculate the maximum Hg input, maximum chlorine input, and/or maximum TSM input anticipated from the new fuels based on supplier data or own fuel analysis, using the methodology specified in Table 6 of this final rule. If the results of recalculating the inputs exceed the average content levels established during the initial test, then you must conduct a new performance test(s) to demonstrate continuous compliance with the applicable emission limit.

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

(9) For boilers and process heaters, you must install, calibrate and operate an oxygen trim system in order to ensure efficient combustion and compliance with the CO standards.

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

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

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

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

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

This proposed rule would require records to demonstrate compliance with each emission limit, operating limit and work practice standard, as specified in the General Provisions. Owners or operators of sources with units with heat input capacity of less than 10 MMBtu/hr, units combusting natural gas or other clean gas, metal process furnaces and limited use units must keep records of the dates and the results of each required boiler tune-up.

Records of either continuously monitored parameter data for a control device if a device is used to control the emissions or continuous monitoring systems (CMS) data are required.

You are required to keep the following records:

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

(2) Continuous monitoring data as required in the rule.

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

(4) Daily hours of operation by each source.

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

(6) Calculations and supporting information of chlorine fuel input, as required in the rule, for each affected source with an applicable HCl emission limit.

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

(8) A paragraph that discusses calculations and supporting information of TSM fuel input, as required in the rule, for each affected source with an applicable total selected metals emission limit.

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

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

(11) A signed statement, as required in the rule, indicating that you burned no new fuels and no new fuel mixture or that the recalculation of total selected metals fuel input demonstrated that the new fuel or new fuel mixture still meets the total selected metals fuel input levels, for each affected source with an applicable total selected metals emission limit.

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

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

(14) A copy of your fuel analysis plan at least 60 days prior to demonstrating initial compliance.

You also are required to submit the following reports and notifications:

(1) Notifications required by the General Provisions.

(2) Initial Notification no later than 120 calendar days after you become subject to this subpart, even if you submitted an initial notification for the vacated standards that were promulgated in 2004.

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

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

(5) Compliance reports semi-annually.

I. How should emissions test results be submitted to the EPA?

The EPA must have performance test data to conduct effective reviews of CAA sections 112 standards, as well as for many other purposes including compliance determinations, emission factor development, and annual emission rate determinations. In conducting these required reviews, the EPA has found it ineffective and time consuming, for us, for regulatory agencies and for source owners and operators, to locate, collect, and submit performance test data because of varied locations for data storage and varied data storage methods. In recent years, however, stack testing firms have typically collected performance test data in electronic format, making it possible to move to an electronic data submittal system that would increase the ease and efficiency of data submittal and improve data accessibility.

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

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

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

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

State, local, and tribal agencies could also benefit from more streamlined and accurate review of electronic data submitted to them. The ERT would allow for an electronic review process rather than a manual data assessment, making review and evaluation of the source provided data and calculations easier and more efficient. Finally, another benefit of the proposed data submittal to WebFIRE electronically is that these data would greatly improve the overall quality of existing and new emissions factors, by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint from industry and regulators is that emission factors are outdated or do not represent a particular source category. With timely receipt and incorporation of data from most performance tests, the EPA would be able to ensure that emission factors, when updated, represent the most current range of operational practices. In summary, in addition to supporting regulation development, control strategy development and other air pollution control activities, having an electronic database populated with performance test data would save industry, state, local, tribal agencies and the EPA significant time, money, and effort while also improving the quality of emission inventories and, as a result, air quality regulations.

J. What are the proposed compliance dates?

The EPA is proposing to reset the compliance date for existing sources to the date 3 years after the date of publication of the final reconsideration rule. For new sources, the EPA is proposing to change the compliance date to 60 days after the date of publication of the final reconsideration rule or upon startup, whichever is later. We are not proposing to change the date that identifies whether a source is new or existing. This date, June 4, 2010, is the publication date of the original proposed rule.

IV. Actions We Are Taking

In this notice, we are granting reconsideration of, and requesting comment on, issues presented in the March 21, 2011, reconsideration notice as well as a subset of other issues raised by petitioners in their petitions for reconsideration. Section V of this preamble summarizes these issues and discusses our proposed responses to each issue.

We have revised the rule language to address provisions related to the reconsideration and are requesting comment on the revised rule text to clarify definitions, applicability, compliance and references to various sections of the rule. Finally, we are proposing technical corrections to certain applicability and compliance provisions in the final rule.

We are seeking public comment only on the issues specifically identified in Section V of this action. We will not respond to any comments addressing other aspects of the final rule or any other related rulemakings.

V. Discussion of Issues for Reconsideration

This section of the preamble contains EPA's basis for our responses to certain issues identified in the petitions for reconsideration and the changes to the rule that we are proposing. We solicit comment on all responses and revisions discussed in the following sections:

A. Surrogates and Selected Regulated Pollutants

1. Alternative Total Selected Metals Limit. Multiple petitioners requested that EPA include an emission limit for TSM as an alternative to the PM limits in the final rule, particularly for biomass units, as part of the reconsideration. After assessing the available data, the EPA determined that inclusion of these limits is appropriate for some subcategories, and the EPA is proposing TSM limits for each subcategory of units that combust solid fuels or Gas 2 fuels. Sources will have the option of meeting either the TSM limit or the alternative PM limit. The TSM measurement, which directly quantifies the HAP metals rather than relying on a surrogate, is a more direct measurement of HAP than PM and is, therefore, appropriate as a pollutant group for regulation with numeric emission limits. For this rule, TSM includes the following eight metals: Arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium. The EPA selected these eight metals, rather than all of the HAP metals other than Hg, because more test data are available for these metals than for the other two HAP metals, cobalt and antimony. The use of 8 of 10 metals should have little or no impact on a facility's selection of controls to meet the standards, and the controls that would be used to reduce emissions of the eight metals would be equally effective in reducing emissions of the other two metals. Therefore, TSM can serve as a surrogate for all metallic HAP except for Hg, which the final rule regulates separately.

For the light liquid, heavy liquid and non-continental liquid units subcategories, we are not proposing alternative TSM emission limits. Instead, we are proposing that these units meet the filterable PM emission limits in all instances. We are not proposing the TSM alternative because of the limited emission test data for TSM and the large variability in the TSM data for these subcategories. Using the EPA's maximum achievable control technology (MACT) floor methodology, the alternative TSM limits resulted in MACT floor values which do not appear to represent the actual performance of the best performing units. The EPA has sent follow-up inquiries to facilities to confirm these data, and is soliciting comment on whether alternative TSM limits are appropriate for the subcategories of units designed to combust liquid fuels. The EPA also is soliciting comment on whether an alternative approach to calculating the TSM MACT floors for these units is appropriate. If the EPA receives sufficient information that supports the alternative TSM standards for units designed to combust liquid fuels, we will consider adopting these limits in the final rule.

2. Work Practice for Dioxin/Furan Emissions. Multiple petitioners requested that EPA reassess the potential for applying work practice standards for dioxins/furans in lieu of numeric emission limits. The EPA has re-assessed the dioxin/furan data sets and has determined that, similar to data for electric utilities for which work practice standards were proposed for dioxins/furans, the large majority of the emission measurements for all of the subcategories are below the level that can be accurately measured using EPA Method 23. While the EPA recognized this as an issue prior to issuing the final rule, sufficient time was not available to fully analyze the issue. For this proposal, the EPA conducted extensive analyses to determine the lowest level of emissions that can be accurately measured using EPA Method 23. The percentages of measurements (test runs) below the method detection level (a level at which the pollutant is known to be present but is not accurately quantified) is about 55 percent, which is 10 percent lower than the percentage for electric utilities. However, in addition to the high percentage of measurements below the method detection level, a very high percentage of measurements are below the level that can be accurately measured (see section V.E.3 of this preamble) for each subcategory. Those percentage are as follows: Coal stoker—100 percent; coal fluidized bed—89 percent; pulverized coal—85 percent; biomass stoker/other—100 percent; biomass fluidized bed—100 percent; biomass dutch oven/pile burner—80 percent; biomass fuel cell—100 percent; heavy liquid—96 percent; light liquid—100 percent; gas 2 (other process gases)—100 percent; non-continental liquid—100 percent (based on No. 6 oil data). While data are not available for two of the biomass subcategories, there is no reason to believe that dioxin emissions for those subcategories would be different than for the other biomass-based subcategories. Based on the percentages of data below the method detection limit coupled with the percentage of data below the level that can be accurately quantified, the EPA concludes that emissions from industrial boilers and process heaters cannot practicably be measured, and the EPA is now proposing work practice standards in place of numeric emission limits for dioxin/furan. The work practice standards require an annual tune-up to ensure good combustion. Details on the assessment of the minimum level that can be accurately measured can be found in the docket memorandum entitled ''Updated data and procedure for handling below detection level data in analyzing various pollutant emissions databases for MACT and RTR emissions limits.'' We do not expect that the change from numeric emission limits to work practice standards will result in less public health protection because the levels of dioxin emitted from units in the source category are at or near current detection level capabilities, and we are not aware of any emissions controls that are demonstrated to reduce dioxin emissions from the low levels indicated by the available data for boilers and process heaters.

B. Output-Based Standards

1. Revisions to Boiler Efficiency Analysis

Petitioners requested that the EPA reassess the calculation of boiler efficiency, which is the key calculation in the development of output-based standards, because the EPA's calculations often resulted in efficiencies that were unrealistically high, often above 100 percent, which is a physical impossibility. The petitioners attributed this to the fact that the EPA had disregarded feedwater temperature (industry average being 280 degrees F). The inclusion of feedwater temperature provides the correct assessment of boiler efficiency because it accounts for the heat energy that is supplied by steam from the boiler to heat the feedwater. The steam used to heat the feedwater is supplied by the boiler and was reported by facilities as part of the boiler ''steam output,'' but was not accounted for in the final rule efficiency calculations. Thus, the EPA has modified the development of the revised output-based emission limits to include the heat (energy) associated with the feedwater. The revised boiler efficiencies of the best performing units for each subcategory were determined by the equation:

Boiler Efficiency = (Steam output (Btu) − Feedwater Input (Btu))/(Fuel Input (Btu))

To calculate ''feedwater input (Btu)'', we used the industry average temperature of 280 degrees F and determined a heat content value of 249.3 Btu/lb. Unit operators provided the ''steam output (Btu)'' for each best performing unit in response to the EPA's information gathering efforts. For all best performing units reporting this steam energy output data, we calculated boiler efficiencies, as well as corresponding input-to-output conversion factors (CF). We averaged CF from the best performing units that have realistic boiler efficiencies averaged and assigned a subcategory-specific conversion factor. Finally, we applied the revised average CF to the proposed input-based emission limits to develop the revised alternate output-based limits. The resultant proposed output-based limits provide a compliance option that achieves emission reductions equivalent to those achieved by the input-based limits and encourage energy efficiency.

2. Other Changes to Output-Based Provisions

a. Accommodating Emissions Averaging Provisions. In order to allow for emissions averaging for units that elect to comply with the output-based emission limits, the EPA is proposing to add additional equations to the rule to allow for emissions averaging as requested by petitioners. Averaging of output based limits was not included in the final rule due to time constraints, but there is no technical reason why averaging of output-based limits is inappropriate. The output-based limits are equivalent to the input-based limits and promote energy efficiency, and, therefore, EPA is proposing to allow averaging for units that elect to comply with the output-based standards.

b. Output-Based Standards for Units that Generate Electricity. Petitioners pointed out that the final output-based standards were not designed to consider efficiency improvements from units that generate electricity only. In response to this concern, the EPA is proposing to add language to the definition of ''Steam output'' that addresses boilers that only produce electricity. The language provides fuel-specific conversion factors for electricity generating units that result in output-based standards in units of pounds per megawatt-hour.

c. Clarification that output-based standards are alternative standards. Petitioners requested that the EPA clarify in the tables that the output-based standards are alternative standards to the input-based standards. The EPA is proposing regulatory text to make this clarification.

d. Legal Authority for Emission Credits. One petitioner questioned the legal authority of the emission credit system and stated that it should be removed from the final rule. However, the petitioner provided no support for its position, and the EPA continues to believe that the emission credit system is consistent with the CAA as promulgated. Therefore, no changes are being proposed. However, we are specifically requesting comment on: (1) The overall concept of the emission credit provision, (2) how to administer it consistently across the country, and (3) available guidelines to inform the delegated authority's decision to approve the implementation plan.

C. Subcategories

In the final rule, the EPA added subcategories for hybrid suspension/grate biomass units, limited-use units, solid fuel units, and non-continental liquid units. The EPA also added a fuel specification to the final rule that would allow units combusting gases not defined as ''Gas 1'' gases to qualify as Gas 1 units by demonstrating that the fuels combusted meet a fuel specification. Petitioners requested that EPA allow comment on these subcategory changes and the fuel specification, and EPA is now soliciting comments on these portions of the final rule, including the changes and particular issues described in sections [1 through 7] below. Petitioners also requested additional subcategories, clarification of several subcategory definitions, and changes to some of the subcategory definitions.

1. *Solid Fuel.* The EPA added a solid fuel subcategory to the final rule that replaced previously proposed separate subcategories for units designed to burn solid fossil-based fuels and units designed to burn solid bio-based fuels. The solid fuel subcategory applied to pollutants identified in the final rule as fuel-based pollutants (PM, HCl, and Hg). Standards for combustion-based pollutants (CO and dioxin/furan), however, were based on specific subcategories for the various types of combustion units, including the specific fuel types the units were designed to combust. The rationale for the change is presented in the preamble to the final rule and the EPA is, in this action, soliciting comments on the solid fuel subcategory.

One significant change is also being proposed related to the solid fuel subcategory. Several petitioners provided information to support the position that PM should be considered a combustion-based pollutant rather than a fuel-based pollutant. After assessing the points raised by the petitioners, the EPA determined that PM emissions are influenced both by fuel type and unit design. Therefore, it is appropriate to treat PM as a combustion-based pollutant. Differences in PM particle size, applicability of air-pollution controls to units combusting various fuels, and the lack of demonstration of certain control technologies on certain designs of boilers (*e.g.,* fabric filters are not used on any hybrid suspension grate boilers) suggest that PM is more appropriately classified as a combustion-based pollutant. Therefore, the EPA is now proposing separate PM limits for each ''combustion-based'' subcategory.

Emission limits for HCl and Hg were developed for the same subcategories as presented in the March 21, 2011, final rule; the only changes associated with the HCl and Hg emission limits are due to new data, corrections to old data, and inventory changes.

2. *Units Designed to Combust Liquid Fuels.* The EPA finalized a single subcategory covering liquid fuel-fired units (with limited exceptions such as non-continental liquid units and limited-used units). Petitioners requested that the EPA reconsider the liquid unit subcategories and include separate subcategories for units designed to combust light liquids and units designed to combust heavy liquids. Petitioners cited issues related to achievability of standards and the types of controls that are used on liquid units but did not cite design differences

that could be used to justify a subcategory. However, we identified several design differences, including the need for steam atomization or high-pressure atomization of heavy liquids, the need for heated storage vessels for heavy liquids in some climates, and the lack of a demonstration that the new source PM limit based on combustion of light liquid fuels had been achieved by any unit combusting heavy liquid fuels. Therefore, the EPA is proposing separate subcategories for heavy liquid-fired and light liquid-fired units for PM and CO, pollutants that are dependent on combustor design. Units designed to combust light and heavy liquids will continue to be grouped together in a liquid fuel subcategory for Hg and HCl, which are the fuel-based pollutants. Light liquids include distillate oil, biodiesel and vegetable oil. Heavy liquids include all other liquid fuels that are combusted in boilers, including byproduct liquid fuels generated at industrial facilities and residual oil. Units that combust any liquid fuels (and less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel) where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids would be considered heavy liquid units. Units that combust any liquid fuels (and less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel) that are not part of the unit designed to burn heavy liquid subcategory would be considered light liquid units.

3. *Non-Continental Liquid Units.* The EPA finalized a subcategory for non-continental liquid units. Stakeholders did not have the opportunity to comment on this subcategory. Therefore, the EPA is now soliciting comments on the non-continental liquid unit subcategory. The preamble to the final rule presents the rationale for the establishment of the subcategory. *See* 76 FR 15635. The EPA also is proposing to revise several of the emission limits for non-continental liquid units due to the receipt of new emissions data for PM and CO from these units and the development of performance estimates based on the combustion of No. 6 fuel oil (rather than all types of liquid fuels). The rationale for estimating the performance of these units based on data from No. 6 oil units is presented below. Petitioners pointed out that non-continental units do not combust distillate oil because of availability issues. While non-continental liquid units typically combust refinery gas, they combust residual oil when process requirements necessitate supplementing the available refinery gas. The petitioners requested that, in the absence of data from non-continental units, emission limits for non-continental units be based on data from liquid units that combust residual oil. The EPA agrees that it would be appropriate to make this change for the combustion-based pollutants due to the design of these units and the unique constraints faced by these units. We now have data for both CO and PM from non-continental units, and there are no longer data gaps for these pollutants. We are thus able to establish numeric emission limits using data from within the subcategory. For fuel-based pollutants, Hg and HCl, the EPA determined that, based on the very limited data sets and the overlap of data for units designed to combust various liquid fuels, it is more appropriate to consider all liquid fuel-fired units together for the development of MACT emission limits. This is consistent with the treatment of Hg and HCl for solid fuel units.

4. *Liquid Units in Alaska.* A petitioner requested that liquid units in Alaska be included in the non-continental liquid unit subcategory or in a separate, newly created subcategory for units in Alaska. The petitioner stated that units in Alaska face the same difficulties with respect to the available supply of natural gas or refinery gas as the non-continental units. The commenter did not provide specific design differences from other types of liquid units. In addition, no test data are available for liquid-fired units in Alaska. Finally, while units in Alaska may face some unique constraints, the design of such units is different from the non-continental units because the units are designed to combust different fuels (*i.e.* non-continental units combust No. 6 fuel oil, which was not reported as a fuel for any unit in Alaska in the responses to the EPA's information collection request). For these reasons, the EPA is not proposing a subcategory for liquid units in Alaska and is not including these units in the non-continental subcategory. The EPA is, however, soliciting comment and supporting rationale on whether a subcategory for liquid units in Alaska is appropriate, and is requesting stack test data that could be used to establish MACT floors if such a subcategory is justified.

5. *Biomass.* Petitioners requested additional biomass subcategories and clarifications to the final subcategories. Suggestions included separate subcategories (for all pollutants) for boilers that are designed to combust kiln-dried wood and for hybrid suspension grate boilers designed to combust bagasse, clarification of which subcategory covers pile burners, and separation of the dutch oven and suspension burner subcategories. In addition to soliciting comment on the proposed changes described below, the EPA is requesting comment on whether additional subcategories are appropriate, as well as data and rationale in support of any additional subcategories.

a. *Boilers Designed to Combust Kiln-Dried Wood.* With respect to a separate subcategory for boilers designed to combust kiln-dried wood, the EPA is proposing a separate subcategory for these units based on the design of the boilers and the unique nature of the facilities that combust this material. These facilities are carefully integrated to utilize their available resources on-site, and the boilers are designed and sized to efficiently combust biomass that has already undergone a drying process that enhances the fuel quality. Care is taken within the facility to maintain the fuel moisture content at levels far lower than virgin biomass materials, typically less than 2 percent moisture. The EPA is proposing emission limits for PM and CO for this subcategory of units that we are calling biomass dry stokers. For HCl and Hg, the final rule's approach of regulating these pollutants under the ''solid fuel subcategory'' for all solid fuel units has not changed.

b. *Hybrid Suspension Grate Boilers Designed to Combust Bagasse.* In the final rule, the EPA added a subcategory for hybrid suspension/grate boilers, which included boilers that are designed to combust very wet biomass fuels such as bagasse. The rationale for the establishment of the subcategory is presented in the preamble to the final rule. *See* 76 FR 15634–15635. Petitioners pointed out that in addition to their unique designs that provide fuel drying within the combustor, these units are highly integrated into the sugar production process and primarily combust specific materials that are generated on-site. Petitioners emphasized that the particle size profile from these units differs significantly from units designed to combust other types of fuels. As discussed in section V.C.1 of this preamble, the EPA is now considering PM to be a ''combustion based'' pollutant. Accordingly, the EPA is proposing emission limits for PM (along with an alternate TSM standard) and CO for these types of units. For HCl and Hg, the final rule's approach of regulating these pollutants under the ''solid fuel subcategory'' for all solid fuel units has not changed.

c. *Clarification of Subcategories for Pile Burners, Dutch Ovens, and Suspension Boilers.* The final rule did not address pile burners, and it established a single subcategory that covered dutch ovens and suspension boilers. Petitioners pointed out that dutch ovens and suspension boilers are inherently different types of boilers and requested EPA to create separate subcategories for those types of units. Petitioners also pointed out that pile burners are very similar to dutch ovens, and, as such, should be included in the dutch oven subcategory. The EPA evaluated these clarification requests and determined that the petitioners' points regarding the design and other differences between dutch ovens and suspension boilers are valid. The EPA agrees that dutch ovens and pile burners should be included in the same subcategory and suspension burners should be a separate subcategory. Therefore, the EPA is proposing separate emission limits for the combustion-based pollutants for these subcategories. All of these types of units will remain in the solid fuel subcategory for the fuel-based pollutants.

6. *Gaseous Fuel Specification.* Multiple petitioners requested reconsideration of the fuel specification that the EPA finalized but did not propose. Petitioners correctly pointed out that the levels of the fuel specification were based only on natural gas and suggested that it would be appropriate to base the fuel specification on levels of contaminants in either natural gas or refinery gas. Petitioners further pointed out that a fuel specification for hydrogen sulfide (H_2S) is not directly related to potential HAP emissions from boilers and process heaters and the H_2S fuel specification should be eliminated from the rule. The EPA has reexamined the fuel specification and agrees that the key contaminant for demonstration of comparability from a HAP perspective is Hg and that the H_2S fuel specification that was finalized does not provide a direct indication of potential HAP from combustion of gaseous fuel. Accordingly, the EPA is proposing a fuel specification based only on the Hg level in the gaseous fuel, and that level is the same level that the EPA included in the March 2011 final rule. The rationale for the Hg fuel specification is included in the preamble to the final rule. *See* 76 FR 15639.

One petitioner stated that the inclusion of a fuel specification demonstrates that emissions can be measured from the units that combust the gaseous fuels, and therefore, the units cannot be regulated by a work practice standard. Regarding this point, the EPA recognizes that the contaminants in the fuel may be able to be measured, but the resulting emissions from combustion of the fuel are another matter entirely. For instance, a unit that combusts a fuel that meets the fuel specification for Hg will have demonstrated that its fuel contains an amount of Hg that is comparable to that found in natural gas. The emissions data for natural gas-fired units show the overwhelming majority of emissions to be below the level that can be accurately quantified by the available test methods. Therefore, the same is expected of units combusting gases with similar contaminant levels to natural gas. Thus, a work practice standard is the appropriate standard for these units. The EPA also is requesting comment on whether additional parameters should be included in the fuel specification.

7. *Work Practices for Limited-Use Units.* The EPA added a subcategory for limited-use units in the final rule, and petitioners requested an opportunity to comment on the creation of the subcategory and the definition of the subcategory. Specifically, multiple petitioners requested that rather than defining the subcategory to include units that operate less than 10 percent of the hours in a year, the EPA define the subcategory to include units that operate with a capacity factor of 10 percent or less. The petitioners believe that such a change would provide more flexibility, but petitioners did not provide support that such a subcategory would qualify for work practice standards under section 112 the CAA. Therefore, the EPA is not proposing a change to the final approach but is requesting comment on how a subcategory defined with a 10 percent capacity factor would qualify for work practice standards in lieu of emission limits. The EPA also is requesting comment on the limited-use subcategory as finalized, and the rationale for the creation of that subcategory can be found in the preamble to the final rule. *See* 76 FR 15634.

D. Monitoring

1. Oxygen monitoring. Petitioners requested reconsideration of the requirement for installation of oxygen monitoring systems on the outlet of the boiler combustion chamber for numerous technical reasons. Several parties expressed concern regarding this location as it is known to be highly stratified, making it very difficult to find a representative location and certify the instrumentation. In reviewing alternatives to this requirement we find that rather than requiring monitoring of oxygen levels in the stack that follows a combustion unit, a better way to ensure good combustion is by requiring the installation, calibration, monitoring and use of oxygen trim systems to optimize air to fuel ratio and combustion efficiency. We agree with petitioners that use of the data from such devices is not only an appropriate control for efficient combustion and a less burdensome alternative to monitoring stack oxygen concentration but also is a better system for many types of units that experience significant load swings and operate with high levels of excess air. Many units are already fitted with these controls, and this proposed change will reduce the monitoring burden for affected units. These systems will provide adequate combustion control to maintain compliance with the CO emission levels demonstrated during the performance test. We seek comment on the appropriateness of using these controls operated as, and for the purposes, described.

2. *PM CEMS.* Petitioners requested reconsideration of the use of PM CEMS as compliance monitors for coal, biomass and residual oil units with heat input capacity greater than 250 MMBtu/hr. Petitioners emphasized that PM CEMS are not demonstrated for biomass units and requested EPA to remove the requirement because of technical issues related to PM particle size and the inability of PM CEMS effectively measure PM from biomass units. Petitioners also stated that PM CEMS are not demonstrated at the low levels that are required by the rule. The EPA agrees that PM CEMS are not demonstrated for biomass units and that significant technical concerns exist regarding the technology's ability to monitor emissions from biomass units. The technical concerns include the fact that PM CEMS are calibrated and certified to measure emissions from a single fuel type. A change in fuel would require a change in the calibration curve of the PM CEMS instrument. The unpredictable variety of biomass fuel constituents as well as biomass fuel moisture content make relying on a single calibration point problematic in terms of compliance assessment when these fuel components change. Furthermore, it is impracticable to replicate, during performance testing, all of the varying fuel conditions necessary for calibrating the monitor. For all of these reasons, it is impractical to appropriately apply PM CEMS to provide the accuracy necessary for

compliance assessment. Accordingly, we are proposing to remove the PM CEMS requirement for biomass units.

Relative to application for other boiler units, several parties expressed concern over the state of readiness of current PM CEMS technology, certification methodology and the technical effort and cost required for the recertification necessary to handle changing fuel and control operating conditions. In our reevaluation of this technology we find that PM monitoring technology would best be employed as parametric monitors (PM CPMS) and used to determine compliance with operating limits rather than emissions limits. This approach reduces the burden of certification of the monitor, which can be a substantial annual cost, and maintains our goals of seeking continuous data monitoring of the source particulate mass emission rate as a 30-day rolling average. We seek comment on the use of these monitors as described in the rule.

3. *CEMS Alternative for Hg.* Petitioners requested reconsideration of the absence of an option to use Hg CEMS for compliance demonstration and monitoring for units subject to Hg limits whose operators do not want to rely on periodic testing, fuel sampling analysis, and parameter monitoring. We have included options in the proposed rule for the use of Hg CEMS. We seek comment on the use of these monitors as described in the rule.

4. *Use of sulfur dioxide (SO_2) CEMS for demonstrating continuous compliance with HCl emission limits.* A petitioner requested that the EPA consider adding a provision to the rule to allow for the use of SO_2 CEMS for demonstration of continuous compliance with the HCl emission limits for sources that are equipped with acid gas controls. While the EPA does not have enough information to propose specific requirements, we believe that a reasonable approach would be to allow for the use of SO_2 CEMS provided that the source demonstrates a correlation between SO_2 control and control of other acid gases emitted from each specific unit that chooses to use SO_2 CEMS. Such a relationship is expected because the available add-on controls for acid gases would provide better control efficiencies for the acid gas HAP than for SO_2, and, therefore, demonstration of SO_2 control using CEMS would provide assurance that the acid gas HAP are being controlled. Therefore, the EPA is soliciting comment on the use of SO_2 CEMS for demonstrating continuous compliance with the HCl emission limits with the condition noted above.

5. *Minimum Data Availability Provisions.* Petitioners noted that the requirement to operate any CMS and collect data at all times is unrealistic and that the agency should include a reasonable minimum data availability limitation allowing for CMS downtime. We have not included any specific minimum data availability requirement for CEMS or other monitoring in the final rule. We disagree with petitioners that we are establishing unreasonable monitoring operating requirements with this rule. Instead, we believe that we are reiterating the source owner's responsibility to operate and maintain the CMS in accordance with existing rules. For example, section 63.8(c) already requires that the source operate the CMS consistent with good air pollution control practices and that the CMS be in continuous operation in accordance with a written quality control program. The final rule clarified that continuous operation does not include periods when the process is not operating and the requirements delineated in the rule otherwise mirror other existing requirements in the MACT general provisions. We do agree with petitioners that a CMS must undergo periodic system inspections, preventive maintenance, and parts replacements in order to continue good operation. It is clear that these events are among normal scheduled quality control events that would be included in the site-specific quality control program that is required under section 63.8(d)(2)(iii) to which the source owner is subject. We also agree that such periods are to be categorized as exceptions to CMS data collection that are already allowed in the rule. Given the existing regulatory requirements and the clarifications in this rule about how to apply those requirements, we believe the rule provides allowances sufficient for CMS operational flexibility and are therefore not proposing any revisions on this issue.

6. *Averaging Times.* The EPA has determined that a 30-day rolling average for parameter monitoring and demonstration of continuous compliance with operating limits is appropriate for this rule. This would be a change from the final rule, which generally included 12-hour block averages that corresponded to the expected length of the longest duration 3-run emission test that was required to demonstrate initial compliance with the emission limits. The operating limits established through performance testing in this rule represent short term process and control operating conditions representative of compliance. Concerns of variability outside the operators control such as fuel content, seasonal factors, load cycling, and infrequent hours of needed operation prompted us to look at longer averaging periods on which to base operating compliance determination. We are aware from studies of emissions over long averaging periods that long term (*e.g.,* 30-day) average emissions for a operating in compliance will have a variability of about half of that represented by the results of short term testing. Given that short term tests are representative of distinct points along a continuum of that inherent operational variability, we believe it appropriate to propose 30-day averages in order to provide a means for the source operator to account for that variability by applying a long term average for establishing compliance. We expect more problematic control system variability (*e.g.,* ESP transformer failure or scrubber venturi fan failure) to result in deviations from a 30-day average relative to compliance almost as much as for a shorter term average.

E. Emission Limits

1. *Additional Data Received.* The EPA received additional data from stakeholders and incorporated all of the data into the MACT database. The new data include 36 Hg test runs, 168 p.m. test runs, 24 dioxin/furan test runs, 133 CO test runs, 63 HCl test runs, and 22 TSM test runs. In addition to the stack test data, the EPA received fuel analyses for 3 facilities and over 51,000 hours of CO CEMS data from 3 facilities. Finally, stakeholders submitted corrections to data and to descriptions of combustion units. We have incorporated these corrections into the project database. For details on the new data and data corrections, see the memorandum in the docket entitled ''Revised Handling and Processing of Corrections and New Data in the EPA ICR Databases (October 2011).''

2. *Quality Assurance Activities on Best Performers.* The EPA requested copies of all of the emission test reports for the best performing units in each subcategory in order to perform additional quality assurance. These test reports document the test results for the summary test data that were submitted to the EPA as part of the EPA's Phase 1 information collection request. This review resulted in multiple changes to data and invalidation of some emission tests. Overall, this effort improved the quality of the data provided by industry. For details on the quality assurance effort, see the memorandum in the docket entitled ''Data Quality Review of Best Performers for PM, Hg, HCl, CO, and Dioxin/Furan Emissions from ICI

Boilers and Process Heaters at Major Sources of HAP (October 2011).''

3. *Incorporation of Minimum Detection Levels and Measurement Imprecision.* In developing the final rule, the EPA incorporated procedures to ensure that the available measurement methods would provide accurate emissions measurements at the levels set for the various standards. The preamble to the final rule described these procedures, but stakeholders did not have an opportunity to comment on them. The EPA has made minor adjustments to the methods used to account for measurement imprecision and presents the rationale in the following paragraphs. We are soliciting comment on the procedures described below.

Test method measurement imprecision is a contributor to the variability of a set of emissions data. One element is associated with method detection capabilities, and a second is a function of the measurement value. Measurement imprecision is proportionally highest for values measured below or near a method's detection level; measurement imprecision proportionally decreases for values measured above the method detection level. The probability procedures applied in calculating the floor or an emission limit inherently and reasonably account for emissions data variability, including measurement imprecision, when the database includes multiple tests from multiple emissions units for which all data are measured significantly above the method detection level. This is less true when the database includes emissions occurring below method detection capabilities that are reported as the method detection level values.

The EPA's guidance to data collection respondents for reporting pollutant emissions specified the criteria for determining test-specific method detection levels. Under those criteria, about a 1 percent probability of an error exists that a pollutant measured at the method detection level is present when in fact it is absent. Such a probability is also called a false positive or the alpha, Type I, error. Because of sample and emissions matrix effects, laboratory techniques, sample size, and other factors, method detection levels normally vary from test to test for any specific test method and pollutant measurement. The expected measurement imprecision is 50 percent or greater. Pollutant measurement imprecision decreases to a consistent relative 10 to 15 percent for values measured at a level about three times the method detection level.[2] Also in accordance with our guidance, source owners identified emissions data which were measured below the method detection level and reported those values as equal to the method detection level as determined for that test. One effect of reporting data in this manner is that the resulting database is somewhat truncated at the lower end of the measurement range (*i.e.,* no values reported below the test-specific method detection level). A floor or emissions limit that is based on a truncated database or otherwise includes values measured near the method detection level may not adequately account for the effects of measurement imprecision on the data variability.

We applied the following procedures to account for the effect of measurement imprecision associated with a database that includes method detection level data. In response to the comments and internal concerns about the quality of measurements at very low emissions limits especially for new sources, we revised the procedure for identifying a representative detection level (RDL). The procedure for determining an RDL starts with identifying all of the available reported pollutant specific method detection levels for the best performing units regardless of any subcategory (*e.g.,* existing or new, fuel type, *etc.*). From that combined pool of data, we calculate the arithmetic mean value. By limiting the data set to those tests used to establish the floor or emissions limit (*i.e.,* from the best performers), the result also represents the best performing testing companies and laboratories, and data from underperforming laboratories are effectively removed from the floor analysis. The outcome should minimize the effect of a test(s) with an inordinately high method detection level (because, for example, 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). We then call the resulting mean of the method detection levels as the RDL as characteristic of accepted source emissions measurement performance.

The second step in the process is to calculate three times the RDL to compare with the calculated floor or emissions limit. This step is similar to what have used before including for the Portland cement MACT determination. We use the multiplication factor of three to approximate a 99 percent upper confidence interval for a data set of seven or more values. For comparing to the floor, if three times the RDL were less than the calculated floor or emissions limit (*e.g.,* calculated from the upper prediction limit (UPL)), we would conclude that measurement variability was adequately addressed. The calculated floor or emissions limit would need no adjustment. If, on the other hand, the value equal to three times the RDL is greater than the UPL, we would conclude that the calculated floor or emissions limit does not account entirely for measurement variability. In this situation, we substituted the value equal to three times the RDL for the calculated floor or emissions limit.

We determined the RDL for each pollutant using data from tests of all the best performers for all of the final regulatory subcategories (*i.e.,* pooled test data). We applied the same pollutant-specific RDL and emissions limit adjustment procedure to all subcategories for which we established emissions limits. We believe that emissions limits adjusted in this manner better ensure that measurement variability is adequately addressed relative to compliance determinations than did the procedure applied for calculations in the June 4, 2010, proposed rule that may have been based on data sets smaller than seven tests and as few as one test. We also believe that the emissions testing procedures and technologies available now and in the future will be adequate to provide the measurement certainty sufficient for sources to demonstrate compliance at the levels of the adjusted emissions limits.

4. *CO CEMS-Based Alternative Emission Limits and Monitoring.* As an alternative to CO stack testing and oxygen monitoring, we are proposing a compliance option that allows the use of CO CEMS. Some petitioners noted that some affected sources currently use CO CEMS and that installing additional monitoring equipment should not be required if a unit elects to comply using existing CO CEMS equipment. In addition, petitioners stated that due to the highly variable nature of CO emissions, an emission limit based on CO CEMS data from boilers over time would more adequately capture the true variability in CO emissions over various operating conditions. In response to these requests, the EPA has calculated a CO CEMS-based MACT floor for each subcategory for which data were available. Facilities would have the option to comply with the alternative

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

CO CEMS-based limits through monitoring with CO CEMS. Through the Section 114 Information Collection Requests and additional voluntary data submittals, a limited amount of CEMS data was available to compute CO CEMS limits. Most sources that reported CEMS data had 30 days of data either reported as hourly or daily averages. Given this limited length of time, we selected a 10-day rolling averaging period in order to allow us to compute multiple data points from each source's dataset. If sources reported CEMS data on both an hourly and daily average basis, we first computed daily averages from the hourly data. Next, we combined the two datasets, sorted the data in sequential calendar data order and computed a series of 10-day rolling averages from each unit. CEMS data on a 10-day rolling average basis could be calculated for the following subcategories: fluidized bed units designed to burn coal/solid fossil fuel, pulverized coal boilers designed to burn coal/solid fossil fuel, stokers designed to burn coal/solid fossil fuel, dutch ovens/pile burners designed to burn biomass/bio-based solids, fluidized bed units designed to burn biomass/bio-based solids, hybrid suspension grate boiler designed to burn biomass/bio-based solids, stokers/sloped grate/others designed to burn wet biomass fuel, suspension burners designed to burn biomass/bio-based solids and units design to burn heavy liquids. CO CEMS data on a 10-day rolling average basis data were not available for the fuel cell units designed to burn biomass/bio-based solids, biomass dry stoker units, and units designed to burn gas 2 (other) gases. Alternate CO CEMS-based limits are not being proposed for these units, but if data are provided for those subcategories prior to March 1, 2012, those data will be considered for use in the final rule. A very limited amount of CEMS data were available from units designed to burn light liquid fuel and units designed to burn liquid fuel located in non-continental States and territories, but not enough data points were available to compute a 10-day rolling average. We do have data sufficient to develop CO CEMS-based limits on a 1-day block average basis for light liquid units and a 3-hour rolling average basis for non-continental liquid units, as discussed below. If sufficient additional data are provided by March 1, 2012, the EPA will consider adjusting the averaging times similar to the other emission limits.

In most cases, only one or two units in each subcategory have CO CEMS data available. The memorandum ''CO CEMS MACT Floor Analysis (October 2011) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source'' provides a complete breakdown of the CO CEMS data that were available. The EPA is requesting the submittal of additional CO CEMS data to achieve a more robust dataset for the purposes of revising the CO CEMS MACT floor calculations. Please provide your dataset in an electronic spreadsheet or database format with the data reduced to hourly CO averages reported as ppmvd. You should include the oxygen associated with each measurement or report the data at a standardized oxygen concentration, preferably adjusted to 3 percent oxygen. The EPA is expecting to receive additional CEMS data before the final rule and to incorporate those data if received in time. The data will likely change the CO CEMS floors, and may also result in different averaging times, depending on the extent of the data.

In order to identify the dataset that would be used to compute a CO CEMS MACT floor emission limit, the EPA first identified all of the units identified as best performers based on their reported stack test results that had 10-day rolling average CO CEMS data available. Refer to the memo ''Revised MACT Floor Analysis (October 2011) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source,'' for more information on how the best performing CO stack tests were identified for each subcategory. However, there was very little overlap in the number of best performing units that had both stack test and CO CEMS data available. After comparing the data, only three subcategories would have best performing units with both stack test and applicable CEMS data. Given these data gaps, we opted to rank CO CEMS data based on each units minimum 10-day rolling average CO CEMS value and then determining the best performers for each subcategory. For the three subcategories where we have CEMS data for units that are part of the stack test-based MACT floors, we included the CEMS data from those units in the CEMS-based floors because those units are demonstrated best performers for CO. We discuss two exceptions below, where the data did not allow the use of a 10-day averaging period. Within each subcategory, we ranked the minimum 10-day rolling averages from lowest to highest to determine the best performing 12 percent. Then, we identified any best performers based on the CO stack test data that provided CO CEMS data, and we included those data in the MACT floor pool. Next, we used all of the daily averages from the best performing units to compute a MACT floor based on a 99 percent UPL.

For the units designed to burn light liquid fuels, the data were insufficient to calculate 10-day rolling averages. Based on the available data, the averaging basis selected was 1 day. For the units designed to burn liquid fuel in the non-continental liquid units subcategory, the data were insufficient to calculate 10-day rolling averages. Based on the available data, the averaging basis selected was 3 hours for non-continental liquid units. Only one of the non-continental boilers submitted CO CEMS data, with a total of 24 hourly averages. In this case, we used each of the hourly averages from this unit to compute a MACT floor based on a 99 percent UPL. The EPA is aware that the averaging time selection and whether rolling or block averaging is selected impacts the UPL calculation and ability to demonstrate compliance. We believe that the averaging times selected for this proposal are reasonable and note that, to some extent, they are dictated by the limited datasets. The EPA is requesting comment on the most appropriate averaging time (*e.g.,* hourly, daily) and length of rolling period (*e.g.,* 10-day, 30-day) to use when calculating the CO CEMS MACT floors and requests specific discussion and new data to support your comments. The length of the averaging time will be affected by the available data in each subcategory. The EPA also is requesting comment on the approach used to calculate the UPL-based MACT floors.

Ranking the dataset according to the minimum 10-day rolling average does not necessarily correlate with the ranking used to identify the best performing 12 percent of units with CO stack test data used to calculate the stack test-based floors for CO. Separate sets of units in the stack test and CEMS data sets create the possibility of incongruent results between the two compliance options. To evaluate whether our selection of the units identified as best performers for CO CEMS data correlates to the units identified as best performers for stack test data, we compared the CEMS data and the computed stack test CO MACT floor for each subcategory. Each unit identified as a best performing unit in the CO CEMS analysis had at least one 3-hour CEMS average at or below the corresponding stack test CO MACT floor for the subcategory, which suggests that the units identified as best performers based on the CEMS data are comparable to the units identified as best performers based on the stack test data. The EPA specifically requests comment on the ranking methodology which should be used, with discussion on whether CO CEMS best performers should be selected from units also identified as best performers from their stack test data, or if a value other than the minimum 10-day rolling average should be used as the basis for ranking the data.

Given the limited data available, the proposed new source CO CEMS floors are similar to existing source floors since the existing source CO CEMS UPL for each subcategory was determined using data from a single unit, with two exceptions. The fluidized bed units designed to burn biomass/bio-based solids and stokers/sloped grate/others designed to burn wet biomass fuel each have two units in the existing source floor calculations, whereas the new source floor would be based on the single best performer. In the case of wet biomass stoker/sloped grate/other, the computed new source floor would be higher than the existing source, so the value reverts to the existing source value.

The 99 percent UPL calculations for CO CEMS used the following statistical formula:

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

Where:

n = the number of daily averages (or hourly averages for non-continental units)

m = the number of test runs in the compliance average

In this case, m equals 10 given the 10-day rolling average compliance period for all subcategories except for non-continental liquid, where m equals 3 for the 3-hour averaging period. Similar to previous analysis of the distribution of the dataset for stack test data MACT floor calculations, the distribution of each CEMS dataset was classified as either a normal distribution or log-normal distribution. In the case of the CEMS datasets from each of the best performers, the datasets were each log-normally distributed. See the ''CO CEMS MACT Floor Analysis (November 2011) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source'' for further details about the calculations.

For each subcategory the analysis showed that the datasets were lognormally distributed. Given the rolling-average compliance metric, many of the datasets also exhibit varying degrees of autocorrelation. Autocorrelation describes the correlation between values of the process at different points in time. Although the UPL calculation is affected by autocorrelation, no adjustments were made to incorporate autocorrelation in this dataset. Depending on the final compliance metric selected, EPA may adjust the dataset for the promulgated rule to better address autocorrelation. The EPA is requesting comment on incorporating autocorrelation into the analysis.

The EPA considered, but is not proposing, an additional final step for establishing the CO CEMS-based floors. When we compared the performance of the units in the top half of the MACT floor pool (usually a single unit) to the UPL-based floor level, it was revealed that the calculated UPL-based floor level resulted in the best performing units in some subcategories not meeting the limit up to about 25 percent of the time. The following final step in the floor setting process for CEMS-based limits could be used to adjust the CO CEMS-based limits to reflect the level achieved at all times by the best performing sources (*i.e.,* the top half of the MACT floor units). In those instances where the best 6 percent of units did not meet the calculated limit at all times, the limit was adjusted to reflect the actual level that was demonstrated to be achieved at all times by those units (the highest 10-day, 1-day, or 3-hour average, as applicable, from the best 6 percent of units). The CO CEMS-based emission limits based on this approach are shown in Table 2 of this preamble. The EPA is requesting comment on whether this final step is appropriate for developing CO CEMS-based MACT floors for boilers and process heaters.

TABLE 2—ALTERNATIVE APPROACH CO CEMS-BASED EMISSION LIMITS FOR BOILERS AND PROCESS HEATERS

Subcategory	Alternate CO CEMS limit, (ppm @3% oxygen)
New and Existing—Coal Stoker	34
New and Existing—Coal Fluidized Bed	78
New and Existing—Coal-Burning Pulverized Coal	35
New and Existing—Biomass Wet Stoker/Sloped Grate/Other	920
New and Existing—Biomass Kiln-Dried Stoker/Sloped Grate/Other	(1)
New and Existing—Biomass Fluidized Bed	480
New and Existing—Biomass Suspension Burner	2,300
New and Existing—Biomass Dutch Ovens/Pile Burners	440
New and Existing—Biomass Fuel Cells	(1)
New and Existing—Biomass Hybrid Suspension Grate	1,400
New and Existing—Heavy Liquid	18
New and Existing—Light Liquid	60
New and Existing—non-Continental Liquid	120
New and Existing—Gas 2 (Other Process Gases)	(1)

[1] No data.

F. MACT Floor Methodology

1. *Standards for Dioxin/Furans.* Petitioners requested that EPA revise the procedure used to calculate the final emission limits for dioxin/furans, with the primary issue being the low levels and how detection limits should be considered. The EPA re-assessed the lowest level that can be accurately measured for dioxin/furan emissions from boilers and process heaters. When we compared those levels to the levels of emissions from all of the units that had test data available, we found that for all subcategories of units, emissions were below the value that can be accurately measured. Details on the establishment of the level that can be accurately measured are provided in the docket memorandum entitled: Updated data and procedure for handling below detection level data in analyzing various pollutant emissions databases for MACT and RTR emissions limits. As discussed in section V.A.2 of this preamble, the EPA is now proposing to regulate dioxin/furan emissions with a work practice standard in lieu of numeric emission limits.

2. *Filling Data Gaps for Non-Continental Liquid Units.* The EPA included numeric emission limits for non-continental liquid units in the final rule. However, data were not available for all of the regulated pollutants, and EPA relied on the MACT floors for liquid units to establish some of the emission limits. Petitioners requested that in cases where data gaps exist, a more appropriate substitution would be to establish floors based on units that combust No. 6 fuel oil, which is the fuel that the non-continental units are designed to combust. While the EPA agrees that for estimating emission from these units, use of data from No. 6 oil-fired units may be appropriate even though some design differences have been identified (see FR 76 15635, March 21, 2011), we are proposing a different approach for setting emission limits for non-continental liquid units. Additional data were submitted to EPA for PM and CO from non-continental units, and the proposed PM and CO limits are based on these data from within the subcategory. For HCl and Hg, which are considered fuel-based pollutants that are not dependent on combustor design, the EPA is proposing to base limits for all liquid units on the entire data set from liquid-fired units. The currently available data and information do not indicate that Hg and HCl should be considered separately for liquid units designed to combust various types of liquids, and we therefore are proposing Hg and HCl emission limits that are based on the available data for all liquid units. The EPA requests comment on this approach, and to the extent that other approaches are suggested, the EPA requests data and rationale to support any suggested alternative approaches.

3. *Selection of Confidence Level for CO.* In the final rule, the EPA selected the use of a 99.9 percent confidence interval for calculating the MACT floor for CO emissions. A petitioner requested reconsideration of this selection given the fact that the EPA used a 99 percent confidence interval for all of the other emission limits in the final rule. The petitioner pointed out that if the data are highly variable, the 99 percent confidence interval should adequately reflect the variability of emissions as well as for the data sets for other pollutants. In the development of the final rule, the 99.9 percent confidence interval was selected in part because the standards covered periods of startup and shutdown, while the data did not reflect CO emissions during those periods. While the EPA finalized work practice standards for startup and shutdown periods, the selection of the confidence interval was not revisited due to time constraints. The EPA is now proposing to use a 99 percent confidence interval in order to maintain a consistent methodology with the development of the MACT floors for other pollutants, and because optional CO CEMS-based limits are being proposed that would allow sources additional flexibility in meeting the requirements of the rule.

G. Tune-Up Work Practices

1. *Requirements for Small and Limited-Use Units.* Petitioners requested that the EPA reconsider the tune-up work practices for a subset of very small units. Specifically, petitioners requested that small natural gas- and light oil-fired units (petitioners defined ''small'' at various levels between 2 MMBtu/hr and 10 MMBtu/hr) be exempted from the rule. While the EPA disagrees that small units should be exempt from the rule, the EPA agrees that for the smallest natural gas-, refinery gas, other clean gas (that meets the fuel specification) and light liquid-fired units, decreased tune-up frequency is appropriate. The large number of small units that can be located at an individual facility, particularly an institution, provides logistical issues with completion of tune-ups on an annual basis. For instance, one institution has over 700 identical small natural gas-fired units that would, under the final rule, each be subject to a biennial tune-up requirement. We are proposing to change that requirement for natural gas-, refinery gas, other clean gas (that meets the fuel specification) and light liquid-fired units equal to or less than 5 MMBtu/hr to a tune-up once every 5 years, with the initial tune-up required by the compliance date and subsequent tune-ups being required at intervals no greater than 5 years from the previous tune-up.

2. *Clarifications of Certain Tune-up Provisions.* Petitioners requested several changes to the tune-up requirements and timing of completing the various aspects of tune-ups. The issues and the EPA's proposed responses, are presented in the following paragraphs.

First, petitioners questioned the requirement that burner inspections (part of the tune-up) must be completed at least once every 36 months, even if this requirement causes a unit to be shut down that otherwise would not have been. The EPA agrees that the burner inspection should not cause units to shut down and is proposing to remove the ''every 36 months'' requirement. Instead, we are proposing that burner inspections that cannot be completed during a tune-up can be delayed until the next scheduled shutdown.

Second, petitioners requested that CO adjustments that are required as part of a tune-up be allowed to be completed within 30 days of the tune-up in order to allow for multiple adjustments and optimization of CO emissions. The EPA agrees that this is a reasonable change and is proposing to allow 30 days from the date the tune-up is completed.

Third, the EPA included a burner inspection requirement that is difficult or impossible for certain units to meet. The EPA is proposing to clarify this provision so as not to require a physical inspection that cannot reasonably be completed.

3. *Conducting Initial Tune-ups at New Sources.* Petitioners requested that the EPA clarify the timing of tune-ups with respect to the compliance dates for existing and new sources. For new units, the EPA recognizes that, as petitioners pointed out, units are generally tuned as part of installation, but a learning curve exists for how to most efficiently operate new units. Accordingly, the EPA is proposing that the initial tune-up after startup must be completed within one year of startup.

H. Energy Assessment

1. *Scope.* Petitioners requested that the EPA clarify the scope of the energy assessment. Specifically, petitioners requested that the scope be clearly limited to only those energy use systems that are located on-site and associated with the affected boilers and process heaters. The final definition for ''Energy

use system'' was intended only to list examples of potential systems that may use the energy generated by affected boilers and process heaters. We did not intend that the energy assessment would include energy use systems using electricity purchased from an off-site source. We also did not intend that the energy assessment include energy use systems located off-site. We are proposing to revise the definition of ''Energy assessment'' to clarify our intent.

2. *Compliance Date.* Petitioners requested that the EPA clarify the due date of the energy assessment. All emission standards must be met by the compliance date, even if compliance demonstrations are sometimes allowed after the compliance date. In order to meet the requirements of the rule, energy assessments must, therefore, be completed by the compliance date for existing sources.

3. *Maximum Duration Requirements.* Petitioners requested that the EPA reconsider the stated ''maximum time'' to conduct the energy assessment because the maximum times were not included in the proposal, and stakeholders had no opportunity to comment. The concern raised by petitioners is that, as the final definition of ''Energy assessment'' is worded, a deviation and a potential violation could occur if the energy assessment effort exceeds these time limits. Our intent for including the ''maximum time'' in the final rule definition was to minimize the burden on the smaller fuel use facilities, many of which are likely small entities, by limiting the extent of the energy assessment. Our concern was that if there was no time limit, these small facilities would have no means to limit the time/effort of an outside energy assessor that is contracted to perform the energy assessment. We have revised the definition of ''Energy assessment'' to change the maximum time from 1 day to 8 technical hours and from three days to 24 technical hours. This would allow sources to perform longer assessments at their discretion.

I. Affirmative Defense Provisions During Malfunctions

The EPA finalized affirmative defense provisions for malfunctions. As part of this reconsideration proposal, we are soliciting comments on the affirmative defense provisions that were included in the final rule. The rationale for the affirmative defense provisions is provided in the preamble to the final rule. *See* 76 FR 15642.

J. Work Practices During Startup and Shutdown

1. *Work Practices.* The EPA finalized a work practice standard for periods of startup and shutdown that requires facilities to minimize emissions consistent with manufacturers' recommended procedures. Petitioners requested that the EPA clarify whether the requirement applies to the boiler or the control device manufacturer. The EPA is proposing to amend the work practice standard so that manufacturers' recommended procedures are no longer referenced, although the EPA expects that facilities will follow such procedures for both the boiler system and any air pollution control devices. The EPA is proposing to amend the work practice standard as described in section III.E of this preamble. The rationale for justifying work practice standards for periods of startup and shutdown is described in the preamble to the final rule. *See* 76 FR 15642. Additionally, we do not have emissions data for startup and shutdown periods sufficient to establish numeric emissions standards for these periods. The only available data is limited CO emissions data, which is unlikely to reflect actual emissions of the best performing units during startup and shutdown. The rationale for the proposed changes to the work practice standard is discussed below. The EPA is now proposing to define startup and shutdown periods and is proposing more specific requirements than those in the final rule. The definitions of startup and shutdown would provide clarity regarding which periods of operation are subject to the work practice standards rather than numeric emission limits and the associated requirements. The proposed definitions specify that only the periods of time between a complete shutdown of a unit (no fuel being combusted) and the time that a unit first reaches 25 percent load qualify as startup, and only the periods of time between the time that a unit last reaches 25 percent load and the time when a unit is completely shut down (no fuel being combusted) qualify as shutdown. These definitions are intended to ensure that units cannot cycle in and out of startup or shutdown. The EPA recognizes that it may be necessary to establish a maximum time period to ensure that units cannot operate in startup or shutdown mode for extended periods of time, and is soliciting comment on the appropriate time period or time periods for the various unit designs. The EPA believes that a work practice standard that applies during such periods should require more than a general duty to reduce emissions, which is essentially what was required in the final rule. General duty requirements do not constitute appropriate work practice standards under section 112(h). We are soliciting comment on the rationale for work practice standards during periods of startup and shutdown as well as the proposed work practice standard and the rationale for proposing changes to the standard. We also are soliciting comment on whether other work practices should be required during startup and shutdown, including requirements to operate using specific fuels to reduce emissions during such periods. Because the EPA did not propose work practice standards for startup and shutdown periods in the June 4, 2010, proposed rule, members of the public did not have the opportunity to comment on those standards or the rationale for the standards prior to issuance of the final rule.

2. *Operating Parameters and Opacity Limits.* Petitioners requested that EPA clarify that the operating limits and opacity limits do not apply during periods of startup and shutdown. Having finalized work practice standards for these periods of time, EPA agrees that the requested clarification is what was intended in the final rule.

K. Applicability

1. *Exemption for Units Serving as Control Devices.* In the final rule, the EPA exempted any boiler or process heater that is used as a control device to comply with another subpart of part 63, 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. Petitioners requested that EPA extend the exemption to units that serve as control devices for EPA standards issued under parts 60 or 61 of the CAA. We recognize that part 61 is another part relevant to the NESHAP program and should be treated the same as the exemption provided for part 63. Although part 60 does not regulate HAP, the EPA does want to continue to use combustion controls for organic pollutants that part 60 addresses, as it provides a pollution prevention strategy and reduces the need for facilities to install other combustion equipment to serve as dedicated control devices for NSPS and NESHAP regulated gas streams (*e.g.,* thermal oxidizers and flares). In addition, many of the potential add-on combustion technologies do not recover energy, and the resulting combustion using these technologies would emit approximately the same level of contaminants as a boiler without the added benefit of

energy recovery. Therefore, the EPA is now proposing to exempt any boiler or process heater that is used as a control device to comply with standards issued under part 60, part 61, or part 63 of the CAA, provided that at least 50 percent of the heat input to the boiler is provided by a gas stream that is subject to standards under those parts.

2. *Waste Heat Boilers and Process Heaters.* Petitioners requested that the EPA clarify that waste heat process heaters, like waste heat boilers, are not subject to the standards. Petitioners are correct that the EPA intended to exempt waste heat process heaters from the rule, and the EPA is amending the definition of process heater to exclude waste heat process heaters. We also are clarifying that waste heat boilers and process heaters can include supplemental burners as long as those burners combust only Gas 1 fuels, up to 50 percent of their heat input.

3. *Units Firing Comparable Fuels.* Petitioners requested that the EPA clarify whether boilers and process heaters burning comparable fuels, as defined under the Resource Conservation and Recovery Act (RCRA), are subject to the NESHAP for industrial, commercial, and institutional boilers and process heaters. Section 261.38 states that hazardous secondary materials (*i.e.,* spent materials, sludges and byproducts) that have fuel value and whose hazardous constituent levels are comparable to those found in fuel oil that could be burned in their place are not solid wastes and hence not hazardous wastes under Subtitle C of RCRA. These materials are called comparable fuels. Since comparable fuels are not hazardous waste, boilers and process heaters burning comparable fuels are not subject to the NESHAP for hazardous waste combustors (part 63, Subpart EEE), which includes boilers and process heaters that burn RCRA hazardous waste. Therefore, boilers and process heaters burning comparable fuels are covered by the NESHAP for industrial, commercial, and institutional boilers and process heaters.

4. *Residential Unit Exemption.* During the initial phases of implementation of the area source boiler rule, stakeholders requested clarification from the EPA on the applicability of the area source rule to residential boilers, particularly those units at individual residences located at institutional facilities. The EPA's intent was not to cover such units, and during reconsideration, the EPA is amending the area source rule accordingly. Similarly, the final major source rule could be interpreted to cover residential boilers at large institutions, which was not the intent of the rule. Accordingly, the EPA is proposing to exempt residential boilers from the rule and is proposing the following definition of residential boiler to the major source rule: *Residential boiler* means a boiler, used in a dwelling containing four or fewer family units, to provide heat and/or hot water. This definition includes boilers used primarily to provide heat and/or hot water for a dwelling containing four or fewer families located at an institutional facility (*e.g.,* university campus, military base, church grounds) or commercial/industrial facility (*e.g.,* farm).

L. Compliance

1. *Extending Compliance Dates.* On May 18, 2011, the EPA issued a stay of the effective date of the final rule. The EPA is proposing several revisions to the standards in this rule. As such, we are proposing to revise the compliance date for existing sources to three years after the date of publication of the final reconsideration rule. This date is being proposed in order to enable facilities sufficient time to install controls and make compliance-related decisions. For new sources, the EPA is proposing that the compliance date is 60 days after the date of publication of the final reconsideration rule, or upon startup, whichever is later. This date assumes that the final reconsideration rule will be subject to the Congressional Review Act, which will delay the effective date of the rule by 60 days. We are proposing to extend the compliance dates for all standards for several reasons. First, the proposed changes to the emission limits for units in every subcategory and the proposed use of work practice standards for dioxin/furan emissions for all subcategories will have a significant impact on the compliance strategies that are selected by the affected sources. For instance, the proposed changes in PM emission limits for existing biomass fluidized bed, hybrid suspension grate, and the newly proposed dry stoker subcategories would require different PM control selections than the emission limits finalized in March 2011. The proposed changes in Hg, HCl and PM emission limits for units designed to burn liquid fuels are likely to result in different compliance responses and control selections for all of these pollutants. For coal stoker units, the increased stringency of the proposed PM and HCl emission limits would require increased control efficiencies that, while not necessarily changing the types of controls needed, may impact the design of those controls. Second, when the EPA announced the reconsideration and postponed the effective date, it indicated to industry that requirements could change significantly. The resulting uncertainty has limited the ability of affected sources to begin making appropriate selections of control technologies and other compliance decisions. Even if significant changes were not being proposed, an extended compliance date would likely be necessary to provide enough time for facilities to achieve compliance. Third, most of the dioxin emission limits that were finalized in March 2011 were below the level that the EPA has now determined can be accurately measured using the required test method. This was pointed out by stakeholders who petitioned the EPA to move to a work practice approach because the levels of dioxin/furan were too low to accurately measure and resulted in a high degree of uncertainty regarding how to meet the limits. The uncertainty resulted in the inability of sources to select dioxin/furan control technology, and also prevented sources from selecting controls for other pollutants because the emission controls must be designed to work properly when operated together. For instance, if a source required an ESP for PM control but needed carbon injection to potentially meet a very low dioxin/furan emission limit, the source may choose a fabric filter for PM control instead of an ESP. Alternatively, if a source no longer needed carbon injection, the particulate loading to the PM control device would be decreased, which may result in a different design or possibly a selection of a different control technology. Finally, the EPA has received comments that the availability of control equipment and vendors to install control equipment for boilers is in question due to the large number of units requiring controls in conjunction with the parallel rulemaking for electric generating units that will require controls from many of the same vendors. While the EPA believes that the maximum time allotted under section 112, 3 years after promulgation along with an additional year for installation of controls that must be approved on a case-by-case basis by the permitting authority, provides enough time for boilers to achieve compliance, the EPA recognizes that maintaining the compliance dates from the March 2011 final rule would essentially provide less than 2 years for sources to meet the final standards, whose stringency will not be determined until the reconsideration is final. For all of the reasons discussed above, the EPA is proposing that the compliance date for existing sources is three years after the date of publication of the final reconsideration rule. The

EPA is requesting comment on the proposed changes to the compliance dates.

2. *Reduced Testing Frequency and Detection Levels.* In the final rule, the EPA changed the stack testing requirements to allow units that demonstrate compliance for a particular pollutant at a level at or below 75 percent of the emission limit for 2 consecutive years to forego stack testing for up to 37 months. The EPA is maintaining this provision for most of the emission limits and is soliciting comment on this provision. The EPA also included, in the final rule analyses, a method to ensure that emission limits are set at levels that can be measured by the available test methods. During the development of the rule, the EPA carefully considered comments regarding the very low levels of some of the finalized emission limits that were based on a level no less than 3 times the ''representative detection limit'' or RDL. In cases where the calculated MACT floors were lower than the 3 times the RDL value, the calculated floor value was replaced by the 3 times the RDL value. For these values, which again represent the lowest level that can be measured, units can qualify for skip testing by meeting the limit rather than a level that cannot be accurately measured.

3. *Fuel Analysis of Gaseous Fuels at Co-Fired Units.* Petitioners requested that the EPA clarify the fuel analysis requirements for co-fired units that combust Gas 1 fuels along with either solid or liquid fuels. The EPA is clarifying that Gas 1 fuels are not included in the fuel analysis requirement.

4. *Coal Sampling Techniques.* Petitioners requested that the EPA allow for automated coal sampling systems. The EPA did not intend to exclude these techniques in the final rule and is adding clarifying language to allow for automated coal sampling techniques.

M. Other Issues Open for Comment

1. Stakeholders asked the EPA to consider, for units that are retrofitted to switch to natural gas as a compliance option, allowing those units to average emissions with units of the original unit design. These parties suggested that continuing to allow such averaging would be consistent with EPA's general approach of specifying emission standards for affected facilities, but otherwise allowing the facilities to comply however they see fit. They also pointed out that this may allow for more effective controls overall. For example, they suggested that without allowing for averaging of units that switch to cleaner fuels as a compliance option, natural gas conversion is a less attractive option than if such averaging was allowed, because a facility would not have the ability to offset emissions using that unit. In this case, these stakeholders believe that installing controls that result in fewer emissions reductions than switching to natural gas may be a perverse outcome. They suggested that continuing to allow averaging across subcategories in cases where fuel switching has been used to achieve compliance would instead encourage fuel switching to cleaner fuels, which is environmentally beneficial. The EPA is requesting comment on the potential benefit of this suggested approach, and how such an approach could be justified and incorporated into the rule.

2. Stakeholders requested that EPA consider creating a subcategory for units that are installed and used in place of flares that are currently used to combust process gases. The EPA is requesting comment on how such a subcategory could be justified and incorporated into the rule. The stakeholders also suggested that it would be appropriate to assume that the emissions from process gases diverted from flares to boilers have ''zero emissions'' for the purposes of classifying the boiler they are combusted in. Since the process gases must be combusted in either event, they requested that the EPA develop an approach where we use a concept similar to the emissions averaging provisions, for example, to simply assume that combustion of such process gases in a boiler rather than a flare should not be counted as emissions from the boiler because there is no net increase in emissions. The EPA requests comment on how such an approach could be justified and incorporated into the rule.

VI. Technical Corrections and Clarifications

We are proposing several technical corrections. These amendments are being proposed to correct inaccuracies and oversights that were promulgated in the final rule and to make the rule language consistent with provisions addressed through this reconsideration. These proposed changes are described in Table 3 of this preamble. We request comment on all of these proposed changes.

TABLE 3—MISCELLANEOUS PROPOSED TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART DDDDD

Section of subpart DDDDD	Description of proposed correction
40 CFR 63.7491(m)	Clarify the language in this paragraph to use the word ''unit'' instead of ''boiler.''
40 CFR 63.7495(b)	Revise this paragraph to include a provision in § 63.6(i)
40 CFR 63.7499(f)–(s)	Revise and add new paragraphs to accommodate the addition of new subcategories of boilers and process heaters.
40 CFR 63.7499(d)	Revise the term ''stokers'' to ''stokers/sloped grate/other units'' consistent with how the data for this rule was analyzed.
40 CFR 63.7500(d)	Revise this paragraph by adding a new paragraph (d) to clarify that the emission standards apply at all times, except during startup and shutdown, during which time you must comply only with Table 3.
40 CFR 63.7501(b)	Revise terms in this paragraph to correct spelling errors.
40 CFR 63.7505(c)	Revise this paragraph by removing the reference to Table 12; this table is not included because this is a proposed rule.
40 CFR 63.7510(a)	Revise this paragraph to create four subparagraphs (1)–(4) to clarify our intent on fuel analysis requirements for gaseous fuels.
40 CFR 63.7510(b)	Revise this paragraph to clarify that certain fuels are not subject to the fuel analysis requirements and that units using a continuous emission monitoring system for mercury or hydrogen chloride are exempt from the performance testing and operating limit requirements.
40 CFR 63.7510(c)	Revise this paragraph to clarify that units using a continuous emission monitoring system for carbon monoxide are exempt from the performance testing and operating limit requirements.
40 CFR 63.7510(d)	Revise this paragraph to clarify that owners and operators electing to comply with the alternative total selected metals limit are not required to install a PM CPMS.

TABLE 3—MISCELLANEOUS PROPOSED TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART DDDDD—Continued

Section of subpart DDDDD	Description of proposed correction
40 CFR 63.7510(g) and (h)	Insert a new paragraph (g) and renumber (g) to (h). Paragraph (g) will clarify the compliance provisions for new sources with respect to the work practice and tune-up provisions.
40 CFR 63.7510(f), 63.7515(f), and 63.7520(d)	Revise these paragraphs by removing the references to Table 12; this table is not included because this is a proposed rule.
40 CFR 63.7521(a)	Revise this paragraph to clarify that fuel analysis cannot be used with gaseous fuels to demonstrate compliance with the limits for total selected metals or hydrogen chloride given method limitations. We are also proposing to revise this paragraph to clarify that a fuel gas system consisting of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required of the combined fuel gas system.
40 CFR 63.7521(b)	Revise this paragraph to clarify that the fuel monitoring plan is needed only if you are required to conduct fuel analyses.
40 CFR 63.7521(b)(1)	Revise this paragraph to add a cross reference to the section describing the initial compliance demonstration.
40 CFR 63.7521(b)(2)(ii) through (iv)	Revise the subparagraphs to clarify that the requirements apply to each anticipated fuel type.
40 CFR 63.7521(c)(1)(ii)	Revise this paragraph by changing wording from "1-hour" to "one-hour". Clarify the different sampling circumstances for performance stack testing and monthly sampling.
40 CFR 63.7521(c)(2)(ii) and 63.7521(d)(2)	Revise this paragraph by clarifying wording describing sampling requirements to provide more flexibility for automated sampling and reduce overly prescriptive language.
40 CFR 63.7521(e)	Reference equations 7, 8, and 9 within this paragraph to add clarity.
40 CFR 63.7521(f)	Add three sub-paragraphs to this paragraph to organize exemptions from fuel specification analyses.
40 CFR 63.7521(g)(1)	Revise this paragraph to add a cross reference to the section describing the initial compliance demonstration.
40 CFR 63.7521(g)(2)(ii) through (iv)	Revise the subparagraphs to clarify that the requirements apply to each anticipated fuel type.
40 CFR 63.7522(b)	Revise this paragraph to add several subparagraphs to clarify that emissions averaging may not include units using CEMS or PM CPMS; that averaging may only be within units in a subcategory subject to the same numerical emission limit; and that emissions averaging is not allowed for certain subcategories of units for certain emission limits.
40 CFR 63.7522(e)(2)	Add the units for emission limits to add clarity (pounds per million Btu). Revise the definition of the term "Sm" in Equation 2 to clarify that maximum steam generation is in units of pounds per hour.
40 CFR 63.7525(a)	Remove a reference to Table 12; this table is not included because this is a proposed rule.
40 CFR 63.7525(b)(3)	Change language from "concentrations" to "rates" to provide clarity.
40 CFR 63.7525(b)(5)	Revise this paragraph by changing wording from "1-hour" to "one-hour".
40 CFR 63.7525(d)(3)	Revise the paragraph to add a reference to 65.7535(d) to replace a description of other situations that constitute a monitoring deviation.
40 CFR 63.7525(d)(4)	Change from the 12-hour block average to 30-day rolling average as specified in the revised Table 8 to subpart DDDDD.
40 CFR 63.7530(b)	Revise this paragraph to clarify which fuels are exempt from analysis by cross-referencing 40 CFR 63.7510(a)(2), instead of repeating the information in that paragraph.
40 CFR 63.7530(b)(4) [formerly (b)(3)]	Revise this paragraph to: 1. Clarify that you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit. 2. Clarify in the subparagraphs which parameters are applicable to specific types of control devices. 3. Add a new subparagraph to address PM controls used in conjunction with a PM CPMS. 4. Add a new paragraph to address particulate wet scrubbers as distinct from acid-gas wet scrubbers.
40 CFR 63.7530(c)(2)	Revise the references to Equation 9 to be Equation 10, to accommodate the change in numbering of equations.
40 CFR 63.7530(c)(3)	Revise the references to Equation 9 to be Equation 10, to accommodate the change in numbering of equations.
40 CFR 63.7530(c)(4)	Revise the references to Equation 9 to be Equation 10, to accommodate the change in numbering of equations.
40 CFR 63.7530(h)	Remove a reference to Table 12; this table is not included because this is a proposed rule.
40 CFR 63.7533(b)(2)	Amend this paragraph to clarify that the use of emission credits from implementation of energy conservation measures can only be used by existing units, and that these credits can be used to demonstrate initial and on-going compliance.
40 CFR 63.7533(c), (c)(1)(i), and (c)(3)	Amend these paragraphs to change the date after which energy conservation measures can be used to generate credits from January 14, 2011, to January 1, 2008. January 1, 2008 is the same cut-off date for using a pre-existing energy assessment to satisfy the energy assessment requirement in Table 3 to subpart DDDDD.
40 CFR 63.7533(c)(2)(i) and (c)(3)	Revise the reference to Equation 12 to Equation 14, to accommodate the change in numbering of equations.
40 CFR 63.7533(c)(3)(i)	Revise Equation 12 in this section to clarify the summation to be performed in that equation, and to clarify that the energy credits are expressed as a decimal fraction of the baseline energy input.
40 CFR 63.7533(c)(3)(i) and (f)	Revise the names and definitions of the terms in Equations 12 and 13 to be consistent.
40 CFR 63.7533(c)(f)	Revise the paragraph to remove the reference to (f)(1) and (2) because there is no paragraph (2) and only a single paragraph is needed.

TABLE 3—MISCELLANEOUS PROPOSED TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART DDDDD—Continued

Section of subpart DDDDD	Description of proposed correction
	Change the reference to Equation 13 to Equation 15, to accommodate the change in numbering of equations.
40 CFR 63.7535	Revise the title of this section to add clarity.
40 CFR 63.7535(b)	Add language to the paragraph to clarify that you must operate monitoring systems while the unit is operating and compliance is required. Add "scheduled CMS maintenance" to the list of periods during which you are not required to collect data from a monitoring system.
40 CFR 63.7535(c)	Amend this paragraph to clarify that operators must record results of CMS performance audits, dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to normal operation. Also adding language to clarify that all collected data must be used to assess compliance.
40 CFR 63.7535(d)	Revise the paragraph to remove references to "out-of-control periods" and to add "system accuracy audits" to the list of periods during which data do not need to be collected.
40 CFR 63.7540(a)	Add references to Tables 1, 2, 3, and 4 to add clarity.
40 CFR 63.7540(a)(2)	Split this paragraph into two subparagraphs for clarity.
40 CFR 63.7540(a)(3)	Revise the paragraph to clarify that fuel analysis for hydrogen chloride is applicable for only solid and liquid fuels, and to clarify that certain fuels are not subject to the fuel analysis requirements.
40 CFR 63.7540(a)(3) and (a)(3)(iii)	Change the references to Equation 9 to Equation 11 to accommodate the change in numbering of equations.
40 CFR 63.7540(a)(4), (a)(5), and (a)(6)	Revise these paragraphs to clarify that certain fuels are not subject to the fuel analysis requirements.
40 CFR 63.7540(a)(5) and (a)(5)(iii)	Change the reference to Equation 11 to Equation 12 to accommodate the change in numbering of equations.
40 CFR 63.7540(a)(9)	Revise this paragraph and the subparagraphs to remove the references to the EPA performance specifications for a PM CEMS, and replace them with a reference to the PM CPMS provisions in the facility's site-specific monitoring plan required by 40 CFR 63.7505.
40 CFR 63.7540(a)(10)(i) and (a)(12)	Revise this paragraph to specify that required burner inspections be done at the next burner shutdown, whether it is scheduled or unscheduled.
40 CFR 63.7541 (a)(3) and (4)	Change the 3-hour parameter averages to 30-day rolling parameter averages to match Table 8 to subpart DDDDD.
40 CFR 63.7545(e)(3)	Remove a reference to Table 12 (this table is not included because this is a proposed rule), and adding language to clarify that this applies to facilities "not using a CO CEMS to demonstrate compliance."
40 CFR 63.7545(f)	Revise the paragraph to include units that burn "gaseous fuel subject to another subpart of this part" to add clarity.
40 CFR 63.7550(c)(6)	Change the reference to Equation 10 to Equation 11, to accommodate the change in numbering of equations.
40 CFR 63.7550(h), (i), and (j)	Revise paragraph (h) and adding paragraphs (i) and (j) to provide additional instruction on submitting data to EPA from performance emission tests, CEMS performance evaluations, and quarterly data from CEMS and CPMS consistent with the proposed monitoring requirements.
40 CFR 63.7555(d)	Remove a reference to Table 12; this table is not included because this is a proposed rule.
40 CFR 63.7555(d)(2)	Correct an inaccurate reference to 40 CFR 241.3(b)(1)and (2), and to add a sentence to clarify that certain units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act do not need to maintain the records described in this paragraph.
40 CFR 63.7555(d)(4)	Change the reference to Equation 10 to Equation 11, to accommodate the change in numbering of equations.
40 CFR 63.7555(d)(5)	Change the reference to Equation 11 to Equation 12, to accommodate the change in numbering of equations.
40 CFR 63.7555(h)	Revise the paragraph to include units that burn "gaseous fuel subject to another subpart of this part" to add clarity.
40 CFR 63.7575	Revise the definition of process heater to include units heating hot water as a process heat transfer medium.
	Edit the definition of each solid fuel combustor design-based subcategory to establish a hierarchy and assisted affected sources by clarifying applicability for units with multiple combustor types.
	Revise the definition of "dutch oven" to clarify that fluidized bed boilers are not part of the dutch oven design category.
	Revise the definition of "energy assessment" to clarify the length of days for each category of facilities.
	Revise the definition of "equivalent" to remove references to hydrogen sulfide.
	Revise the definition of "fluidized bed boiler" to clarify that pulverized coal boilers are not included.
	Revise the definition of "hybrid suspension grate boiler" to clarify that "the fuel combusted in these units exceed a moisture content of 40 percent on an as-fired basis" and "Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category."
	Revise the definition of "fuel cell" to clarify that "fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory."
	Revise the definition of "liquid fuel" to include vegetable oil.

TABLE 3—MISCELLANEOUS PROPOSED TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART DDDDD—Continued

Section of subpart DDDDD	Description of proposed correction
	Revise the definition of ''process heater'' to include ''units heating hot water as a process heat transfer medium'' and to clarify that ''waste heat process heaters are excluded from this definition'' similar to the exemption allowed for waste heat boilers.
	Revise the definition of ''steam output'' to include a description of the total energy output for a boiler that generates only electricity.
	Revise the definition of ''stoker'' to clarify that ''fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.''
	Revise the term ''suspension boiler'' to instead be ''suspension burner'', to provide consistent terminology throughout the rule and to clarify that ''fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.''
	Revise the definition of ''waste heat boiler'' to clarify that the definition includes fired and unfired waste heat boilers.
	Revise the definition of ''waste heat process heater to clarify that the definition includes fired and unfired waste heat process heaters.
	Add new definitions of ''30-day rolling average'', ''average annual heat input rate'', ''biodiesel'', ''daily block average'', ''heavy liquid'', ''light liquid'', ''other combustor'', ''oxygen analyzer'', ''oxygen trim system'', ''pile burner'', ''residential boiler'', ''sloped grate'', ''stoker/sloped grate/other unit designed to burn kiln dried biomass'', ''stoker/sloped grate/other unit designed to burn wet biomass'', ''total selected metals'', ''unit designed to burn heavy liquid subcategory'', ''unit designed to burn light liquid subcategory'', and ''vegetable oil''.
	Remove the definition of ''liquid fuel subcategory.''
Tables 1 and 2 to subpart DDDDD	Revise the sampling volumes collected and also the prescribed span values associated with the emission measurement methods to account for changes in the numerical emission limits and to be consistent with the proposed emission limits.
Table 3 to subpart DDDDD	Revise items 1, 2, and 3 to account for the proposed changes in the tune-up requirements.
	Revise item 4c to clarify the major systems ''consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.''
	Revise item 5 to remove the reference to Table 12; this table is not included because this is a proposed rule.
Table 4 to subpart DDDDD	Revise the operating limits for items 1 and 2 to read ''one-hour'' instead of ''1-hour''.
	Revise certain items in the table to clarify the applicability of the parameter operating limits, and to reflect that replace PM CEMS with PM CPMS requirements.
	Revise items 1, 2, and 4 in the table to reflect the fact that we are proposing that compliance with the operating limits is based on a 30-day rolling average.
Table 6 to subpart DDDDD	Revise items 1, 2, and 3 to provide additional instruction on demonstrating compliance.
	Revise item 4 to replace the requirements for hydrogen sulfide in other gas 1 fuels with requirements for total selected metals in solid fuels.
Table 7 to subpart DDDDD	Revise item 1 to include total selected metals with PM and mercury, and to clarify the applicability of the operating limits described in that item.
Table 8 to subpart DDDDD	Include provisions for demonstrating continuous compliance with a PM CPMS, to reflect proposed changes elsewhere in the rule.
	Revise various items to reflect the proposed change from 12-hour block averages to 30-day rolling averages for demonstrating compliance.
	Revise the operating load compliance provisions to be consistent with the operating limit in Table 4 to subpart DDDDD.
Table 11 to subpart DDDDD	Delete Table 11 to subpart DDDDD to be consistent with the proposal to remove the numerical emission limits for dioxin/furan emissions.
Table 12 to subpart DDDDD	Remove Table 12 to subpart DDDDD because this is a proposed rule and Table 12 was needed only because the rule published on March 21, 2011 (76 FR 15608) was a final rule.

VII. Impacts of This Proposed Rule

A. What are the air impacts?

Table 4 of this preamble illustrates, for each basic fuel subcategory, the emissions reductions achieved by the proposed rule (*i.e.,* the difference in emissions between a boiler or process heater controlled to the floor level of control and boilers or process heaters at the current baseline) for new and existing sources. Nationwide emissions of selected HAP (*i.e.,* HCl, HF, Hg, metals, and volatile organic compound (VOC)) will be reduced by 45,000 tons per year for existing units and 19 tons per year for new units. Emissions of HCl will be reduced by 37,000 tons per year for existing units and 0 tons per year for new units. Emissions of Hg will be reduced between 0.5 to 1.8 tons per year for existing units and 20.2 pounds per year for new units. Emissions of filterable PM will be reduced by 41,200 tons per year for existing units and 1,500 tons per year for new units. Emissions of non-mercury metals (*i.e.,* antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium) will be reduced by 2,200 tons per year for existing units and 19 tons per year for new units. In addition, emissions of SO_2 are estimated to be reduced by 558,400 tons per year for existing sources and 0 tons per year for new sources. A discussion of the methodology used to estimate emissions and emissions reductions is presented in ''Revised (November 2011) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

TABLE 4—SUMMARY OF EMISSIONS REDUCTIONS FOR EXISTING AND NEW SOURCES

[Tons/yr]

Source	Subcategory	HCl	PM	Non mercury metals [a]	Mercury [b]	VOC
Existing Units	Limited Use	1	2	0.45	2.2E–04	1
	Solid units	34,815	34,830	271	0.4 to 1.4	2,487
	Liquid units	2,039	6,240	1,905	0.04 to 0.3	1,815
	Non-Continental Liquid units	158	29	4	0.001 to 0.01	169
	Gas 1 (NG/RG) units	21	118	0.9	0.01	85
	Gas 1 Metallurgical Furnaces	0.4	3	0.02	0.001	23
	Gas 2 (other) units	4	11	0.07	0.004 to 0.005	138
New Units	Solid units	0	1,462	19	0.01	0
	Liquid units	0	0	0	0	0
	Gas 1 units	0	0	0	0	0
	Gas 1 Metallurgical Furnaces	0	0	0	0	0
	Gas 2 (other) units	0	0	0	0	0

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

[b] Hg reductions are presented as a range due to adjustments on reported fractions and limits of detection. See memorandum entitled ''Revised (November 2011) Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source'' for a description of the two methods for estimating Hg reductions.

B. What are the water and solid waste impacts?

The EPA estimated the additional water usage that would result from installing wet scrubbers to meet the emission limits for HCl would be 1.2 billion gallons per year for existing sources and 0 gallons per year for new sources. In addition to the increased water usage, an additional 416 million gallons per year of wastewater would be produced for existing sources and 0 gallons per year for new sources. The annual costs of treating the additional wastewater are $2.3 million for existing sources and $0 for new sources. These costs are accounted for in the control costs estimates.

The EPA estimated the additional solid waste that would result from the MACT floor level of control to be 286,000 tons per year for existing sources and 1,700 tons per year for new sources. Solid waste is generated from flyash and dust captured in PM and Hg controls as well as from spent carbon that is injected into exhaust streams or used to filter gas streams. The costs of handling the additional solid waste generated are $12.0 million for existing sources and $70,600 for new sources. These costs are also accounted for in the control costs estimates.

A discussion of the methodology used to estimate impacts is presented in ''Revised (November 2011) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the Docket.

C. What are the energy impacts?

The EPA expects an increase of approximately 1.5 billion kilowatt hours (kWh) in national annual energy usage as a result of the proposed rule. Of this amount, 1.4 billion kWh would be from existing sources and 120 million kWh from new sources. The increase results from the electricity required to operate control devices, such as wet scrubbers, electrostatic precipitators, and fabric filters which are expected to be installed to meet the proposed rule. Additionally, the EPA expects work practice standards such as boilers tune-ups and combustion controls will improve the efficiency of boilers, resulting in an estimated fuel savings of 47.3 trillion BTU each year from existing sources. The EPA did not estimate fuel savings and efficiency improvements on new boilers since new boilers are expected to be tuned-up up upon installation and will not achieve additional fuel savings in the first year. This fuel savings estimate includes only those fuel savings resulting from Gas 1, liquid, and coal fuels and it is based on the assumption that the work practice standards will achieve 1 percent improvement in efficiency.

D. What are the cost impacts?

To estimate the national cost impacts of the proposed rule for existing sources, we developed average baseline emission factors for each fuel type/control device combination based on the emission data obtained and contained in the Boiler MACT emission database. If a unit reported emission data, we assigned its unit-specific emission data as its baseline emissions. For units that did not report emission data, we assigned the appropriate emission factors to each existing unit in the inventory database, based on the average emission factors for boilers with similar fuel, design, and control devices. We then compared each unit's baseline emission factors to the proposed MACT floor emission limit to determine if control devices were needed to meet the emission limits. The control analysis considered fabric filters and activated carbon injection to be the primary control devices for Hg control; electrostatic precipitators for units meeting Hg limits but requiring additional control to meet the PM or total selected metals limits; wet scrubbers or fabric filters with dry injection to meet the HCl limits; tune-ups, replacement burners, combustion controls, and oxidation catalysts for CO and organic HAP control; and tune-ups for dioxin/furan control. We identified where one control device could achieve reductions in multiple pollutants, for example a fabric filter was expected to achieve both PM and Hg control, in order to avoid overestimating the costs. We also included costs for testing and monitoring requirements contained in the proposed rule. The resulting total national cost impact of the proposed rule is 5.4 billion dollars in capital expenditures and 1.9 billion dollars per year in total annual costs. Considering estimated fuel savings resulting from work practice standards and combustion controls, the total annualized costs are reduced to 1.5 billion dollars. The total capital and annual costs include costs for control devices, work practices, testing and monitoring. While these costs are higher than the costs estimated for the final rule, these estimates are based on an inventory that includes 300 additional units that were identified after the final rule was completed. The costs associated with the final rule inventory are just under $5.0 billion in capital expenditures and $1.75 billion in total annual costs ($1.35 billion considering fuel savings). Table 5 of this preamble shows the capital and annual cost impacts for each subcategory. Costs include testing and monitoring costs, but not recordkeeping and reporting costs.

TABLE 5—SUMMARY OF CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES

Source	Subcategory	Estimated/ Projected number of affected units	Capital costs (10^6 $)	Testing and monitoring annualized costs (10^6 $/yr)	Annualized cost(10^6 $/yr) (considering fuel savings)
Existing Units	Coal units	616	2,713	46	953
	Biomass units	508	639	33	169
	Heavy Liquid units	322	769	8.4	264
	Light Liquid units	581	930	5.1	277
	Non-Continental Liquid units	44	181	1.5	42
	Gas 1 (NG/RG) units	11,911	77	0.9	(295)
	Gas 2 (other) units	129	132	2.3	55
Energy Assessment	ALL	1,704 (Facilities)	N/A	N/A	28
New Units	Coal units	0	0	0	0
	Biomass units	82	381	5.6	[a] 99
	Liquid units	0	0	0	0
	Gas 1 (NG/RG) units	1,762	11	0	[a] 5.1
	Gas 2 (other) units	0	0	0	0

[a] Total annualized costs for new units do not account for fuel savings since no fuel savings are estimated in the first year for new units.

Using Department of Energy projections on fuel expenditures, the number of additional boilers that could be potentially constructed was estimated. The resulting total national cost impact of the proposed rule for new boilers in the 3rd year is 393 million dollars in capital expenditures and 104 million dollars per year in total annual costs.

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

A discussion of the methodology used to estimate cost impacts is presented in ''Revised (November 2011) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the Docket.

E. What are the economic impacts?

The EPA analyzed the economic impacts of this proposed rule using the methodology that was discussed in the final rule RIA and in the preamble to the final rule. *See* FR 76 15651. The market impact results are very similar to the results presented in the final rule and the RIA. The agency's economic model suggests the average national price increases for industrial sectors are less than 0.01 percent, while average annual domestic production may fall by less than 0.01 percent. Because of higher domestic prices, imports slightly rise. The increase in US trade deficit is now 1.93 billion dollars (2006$). For the RIA, it was 1.86 billion dollars (2006$). The results for sales tests for small businesses were somewhat reduced. For the sales tests using small companies identified in the Combustion Survey, the mean cost to receipts dropped from 4 percent in the RIA to 2 percent for this proposed rule and the median was 0.2 percent for both. The number of parent companies with sales tests exceeding 3 percent dropped from 8 in the RIA to 6 for this proposed rule. There was no change in the results for small public entities. Median cost is still about $1.1 million and representative small major public entities would have cost-to-revenue ratios above 10 percent. The change in employment estimates between the RIA and the proposal is minimal. In the RIA for the final rule, we estimated employment changes ranging between −3100 to +6,500 employees, with a central estimate of +1,700. For this proposal, we estimate employment changes ranging between −3000 to +6,300 employees, with a central estimate of +1,600. These estimated annual employment changes compared to the baseline employment, and are for the time period for which the annualized cost applies (2015 to 2029).

The benefits estimates increased for this proposal. In the RIA for the final rule, we estimated benefits ranging from $22 billion (2008$) to 54 billion (2008$) at a 3 percent discount rate. For this proposal, we estimate benefits ranging from $27 billion (2008$) to 67 billion (2008$) at a 3 percent discount rate. The range for the RIA was $20 billion (2008$) to 49 billion (2008$) at a 7 percent discount rate. The range for this proposal is $25 billion (2008$) to 61 billion (2008$) at a 7 percent discount rate.

F. What are the benefits of this proposed rule?

We calculated health benefits using the methodology described in the RIA prepared for the March 21, 2011, final rule. We incorporated the revised emission reductions estimated for this reconsideration proposal into the analysis. We were unable to estimate the benefits from reducing exposure to HAP and ozone, ecosystem impairment, and visibility impairment, including reducing 187,000 tons of carbon monoxide, 37,000 tons of HCl, 1,000 tons of HF, 1,000 to 3,600 pounds of Hg, and 2,200 tons of other metals. Please refer to the full description in the final Boiler RIA of the unquantified benefits as well as technical details of the analysis and its limitations and uncertainties. These monetized benefits are approximately 23 percent higher than the final rule benefits due to the increase in SO_2 emission reductions associated with the additional units affected by the rule and the revised HCl limit. We estimate the total monetized benefits of this proposed regulatory action to be $27 billion to $67 billion (2008$, 3 percent discount rate) in the implementation year (2015). A summary of the monetized benefits estimates at discount rates of 3 percent and 7 percent is provided in Table 6 of this preamble. A summary of the avoided health incidences is provided in Table 7 of this preamble.

TABLE 6—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT

[Millions of 2008$] [1]

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
$PM_{2.5}$-related benefits:			
Direct $PM_{2.5}$	25,601	$1,800 to $4,500	$1,700 to $4,100.
SO_2	558,430	$25,000 to $63,000	$23,000 to $57,000.
Total		$27,000 to $67,000	$25,000 to $61,000.

[1] All estimates are for the implementation year (2015), and are rounded to two significant figures so numbers may not sum across rows. All fine particles are assumed to have equivalent health effects. Benefits from reducing hazardous air pollutants (HAP) are not included. These estimates do not include energy disbenefits valued at $5.8 to $75 million depending on the discount rate. These benefits reflect existing boilers and new boilers anticipated to come online by 2015.

TABLE 7—SUMMARY OF THE AVOIDED HEALTH INCIDENCES FOR THE FINAL BOILER MACT [1]

	Avoided health incidences
Avoided Premature Mortality	3,100–8,000
Avoided Morbidity	
Chronic Bronchitis	2,000
Acute Myocardial Infarction	4,900
Hospital Admissions, Respiratory	750
Hospital Admissions, Cardiovascular	1,600
Emergency Room Visits, Respiratory	3,000
Acute Bronchitis	4,600
Work Loss Days	390,000
Asthma Exacerbation	51,000
Minor Restricted Activity Days	2,300,000
Lower Respiratory Symptoms	55,000
Upper Respiratory Symptoms	41,000

[1] All estimates are for the implementation year (2015), and are rounded to two significant figures. All fine particles are assumed to have equivalent health effects. Benefits from reducing HAP are not included. These benefits reflect existing boilers and new boilers anticipated to come online by 2015.

G. What are the secondary air impacts?

For units adding controls to meet the proposed emission limits, we anticipate very minor secondary air impacts. The combustion of fuel needed to generate additional electricity would yield slight increases in emissions, including nitrogen oxide (NO_X), CO and SO_2 and an increase in carbon dioxide (CO_2) emissions. Since NO_X and SO_2 are covered by capped emissions trading programs, these pollutants do not contribute disbenefits from additional electricity demand. Additional CO_2 emissions from increased electricity consumption are estimated to be 931,000 tons per year from existing units and 79,700 tons per year from new units. Energy disbenefits due to increased CO_2 emissions range from $5.8 million to $75 million depending on the discount rate, and thus do not affect the rounded monetized benefits.

VIII. Relationship of This Proposed Action to Section 112(c)(6) of the Clean Air Act

Section 112(c)(6) of the CAA requires the 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). The 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: polycyclic organic matter (POM) and Hg. (The POM emitted is composed of 16 polyaromatic hydrocarbons and extractable organic matter.) In the **Federal Register** notice *Source Category Listing for Section 112(d)(2) Rulemaking Pursuant to Section 112(c)(6) Requirements,* 63 FR 17838, 17849, Table 2 (1998), the 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.

For Hg, the 112(c)(6) requirement is directly met through the proposed emission limits for Hg. Through these emission limits, the types of boilers and process heaters listed in section 112(c)(6) are subject to regulation.

For POM, which are byproducts of combustion, the formation of POM is effectively reduced by the combustion and post-combustion practices required to comply with the CAA Section 112 standards. The tune-up requirement for all major source units and the CO emission limits will ensure that good combustion practices are followed, thus minimizing emissions of organic HAP, including POM. Any POM that do form during combustion would be reduced by the various post-combustion controls. The add-on PM control systems (either fabric filter or wet scrubber) and activated carbon injection in the fabric filter-based systems would reduce emissions of these organic pollutants. It is, therefore, reasonable to conclude that POM emissions will be substantially controlled. Thus, while this final rule does not identify specific numerical emission limits for POM, emissions of POM are, for the reasons noted below, nonetheless ''subject to regulation'' for purposes of Section 112(c)(6) of the CAA. In lieu of establishing numerical emissions limits for pollutants such as POM, we regulate surrogate substances. While we have not identified specific numerical limits for POM, CO serves as an effective surrogate for this HAP, because CO, like POM, is formed as a byproduct of combustion, and both would increase with an increase in the level of incomplete combustion. Consequently, we have concluded that the emissions limits for CO function as a surrogate for control of POM, such that it is not necessary to require numerical emissions limits for POM with respect to boilers and process heaters to satisfy CAA Section 112(c)(6).

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

IX. Statutory and Executive Order Reviews

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

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

Because this action is proposing changes to a final rule and does not increase costs by an amount that would qualify the proposed rule, by itself, as a major rule, the EPA did not prepare a new RIA for this action. Instead, the EPA prepared an assessment of the changes in the costs and benefits of this proposed rule compared to the costs and benefits associated with the March 21, 2011, final rule. Overall, the costs and impacts are estimated to be similar to the costs and impacts associated with the final rule, although the distribution is somewhat different and the number of affected units in the inventory has increased by about 300 units. When comparing the costs using only those sources that were part of the final rule inventory, the costs have decreased. The EPA re-ran the multimarket model to assess changes in economic impacts, and this analysis confirmed that the overall economic impacts are similar to the final rule. The benefits are projected to increase by about 23 percent because of the increase in the estimated SO_2 reductions. A summary of the costs and benefits of the final rule is provided in the preamble to the final rule (*see* 76 FR 15658) and the detailed analysis for the final rule is provided in the RIA for the final rule. In addition, memoranda are provided in the docket to document the changes in costs, economic impacts, and benefits associated with this proposed rule.

B. Paperwork Reduction Act

The information collection requirements in this proposed rule will be submitted for approval to the OMB under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number 2028.07. The information collection requirements are not enforceable until OMB approves them.

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

This proposed rule would require maintenance inspections of the control devices but would not require any notifications or reports beyond those required by the General Provisions aside from a notification of intent to commence burning solid waste materials and notification of alternative fuel use for those units that are in the Gas 1 subcategory but burn liquid fuels for periodic testing, or during periods of gas curtailment or gas supply emergencies. The recordkeeping requirements require only the specific information needed to determine compliance. 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 $96.2 million. This includes 324,954 labor hours per year at a total labor cost of $30.7 million per year, and total non-labor capital costs of $65.5 million per year. This estimate includes initial and annual performance test, conducting an documenting an energy assessment, conducting fuel specifications for Gas 1 units, repeat testing under worst-case conditions for solid fuel units, conducting and documenting a tune-up, semiannual excess emission reports, maintenance inspections, developing a monitoring plan, notifications, and recordkeeping. Monitoring, testing, tune-up and energy assessment costs and cost were also included in the cost estimates presented in the control costs impacts estimates in section VII.D of this preamble. The total burden for the Federal government (averaged over the first 3 years after the effective date of the standard) is estimated to be 97,613 hours per year at a total labor cost of $5.1 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 it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

To comment on the agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, the EPA has established a public docket for this rule, which includes this ICR, under Docket ID number EPA–HQ–OAR–2002–0058. Submit any comments related to the ICR to the EPA and OMB. See **ADDRESSES** section at the beginning of this notice for where to submit comments to the EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503, Attention: Desk Office for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after December 23, 2011, a comment to OMB is best assured of having its full effect if OMB receives it by January 23, 2012. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities.[3] The RFA also allows an agency to ''consider a series of closely related rules as one rule for the purposes of sections'' 603 (initial regulatory flexibility analysis) and 604 (final regulatory flexibility analysis) in order to avoid ''duplicative action.'' 5 U.S.C. 605(c). This proposed rule is closely related to the final major source rule, which the EPA signed on February 21, 2011. The EPA prepared initial regulatory flexibility analyses in connection with the major source rule. Therefore, pursuant to § 605(c), the EPA is not required to complete an initial regulatory flexibility analysis for this rule.

The EPA has been concerned with potential small entity impacts since it began developing the major source rule. The EPA conducted outreach to small entities and, pursuant to § 609 of RFA, convened a Small Business Advocacy Review Panel to obtain advice and recommendations from small entity representatives.

Pursuant to the RFA, the EPA used the Panel's report and prepared both an initial regulatory flexibility analysis and a final regulatory flexibility analysis in connection with the closely related major source rule. Convening an additional Panel and preparing an additional initial regulatory flexibility analysis would be procedurally duplicative and is unnecessary given that the issues here are within the scope of those considered by the Panel. In addition, this reconsideration proposal would decrease capital and annualized costs on small entities by about 3 percent and 10 percent, respectively, relative to the closely related final rule. We invite comments on the aspects of the proposal outlined in section V of this preamble and their impacts on small entities.

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

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538, requires federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. This March 21, 2011, final rule contained 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 one year. Accordingly, the EPA prepared under section 202 of the UMRA a written statement for the final rule. The discussion below has been updated to reflect the proposed changes.

1. Statutory Authority

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

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

2. Social Costs and Benefits

The regulatory impact analysis prepared for the final rule, which we have not revised for this proposed rule, including the agency's assessment of costs and benefits, is detailed in the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011)'' in the docket. Based on estimated compliance costs associated with this proposed rule and the predicted change in prices and production in the affected industries, the estimated social costs of this proposed rule are $1.49 billion (2008 dollars).

It is estimated that 3 years after implementation of this proposed rule, HAP would be reduced by 45,000 tons per year, including reductions in HCl, hydrogen fluoride, metallic HAP including Hg, and several other organic HAP from boilers and process heaters. Studies have determined a relationship between exposure to these HAP and the onset of cancer, however, the agency is unable to provide a monetized estimate of the HAP benefits at this time. In addition, there are significant annual reductions in fine particulate matter ($PM_{2.5}$) and in SO_2 that would occur, including 25,000 thousand tons of $PM_{2.5}$ and 558 thousand tons of SO_2. These reductions occur within 3 years after the implementation of the proposed regulation and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) is a reduction in premature mortality. Other health effects associated with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks, and work-lost days (*i.e.,* days when employees are unable to work). While we are unable to monetize the benefits associated with the HAP emissions reductions, we are able to monetize the benefits associated with the $PM_{2.5}$ and SO_2 emissions reductions. For SO_2 and $PM_{2.5}$, we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2015 associated with the implementation of the proposed alternative range from $27 billion (2008 dollars) to $67 billion (2008 dollars) when using a 3 percent discount rate (or from $25 billion (2008 dollars) to $61 billion (2008 dollars) when using a 7 percent discount rate). This estimate, at a 3 percent discount rate, is about $25 billion (2008 dollars) to $65 billion (2008 dollars) higher than the estimated social costs shown earlier in this section. The general approach used to value benefits is discussed in more detail earlier in this preamble. For more detailed information on the benefits estimated for the rulemaking, refer to the RIA and the memos updating the impacts and benefits in the docket.

3. Future and Disproportionate Costs

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

We do not believe that there will be any disproportionate budgetary effects of this proposed rule on any particular areas of the country, state or local governments, types of communities (*e.g.,* urban, rural), or particular industry segments. See the results of the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011).''

4. Effects on the National Economy

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

The nationwide economic impact of this proposed rule is presented in the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011)'' and two memoranda that are included in the docket, entitled ''Health Benefits for Boiler MACT Reconsideration Proposal'' and ''Regulatory Impact Results for the Reconsideration Proposal for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources,'' which update the RIA analyses. This analysis provides estimates of the effect of this rule on some of the categories mentioned above. The results of the economic impact analysis are summarized previously in this preamble. The results show that there will be a small impact on prices and output, and little impact on communities that may be affected by this proposed rule. In addition, there should be little impact on energy markets (in this case, coal, natural gas, petroleum products, and electricity). Hence, the potential impacts on the categories mentioned above should be small.

5. Consultation With Government Officials

The UMRA requires that we describe the extent of the agency's prior consultation with affected state, local, and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, section 203 of the UMRA requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a proposal. We consulted with State and local air pollution control officials during the development of the final rule. We have also held meetings on this proposed rule with many of the stakeholders from numerous individual companies, institutions, environmental groups, consultants and vendors, labor unions, and other interested parties. We have added materials to the docket to document these meetings.

Consistent with section 205, the EPA has identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives is presented in the docket. The regulatory alternative upon which the emission limits in this proposed rule are based represents the MACT floors for all subcategories and, as a result, it is the least costly and least burdensome alternative.

This rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have some sources affected by this proposed rule, the impacts are not expected to be significant. Therefore, this proposed rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This proposed rule will not impose direct compliance costs on state or local governments, and will not preempt state law. Thus, Executive Order 13132 does not apply to this action.

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

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). It will not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

The EPA specifically solicits additional comment on this proposed action from tribal officials.

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

The EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it 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. For the March 21, 2011, final rule, we estimated a 0.05 percent price increase for the energy sector and a −0.02 percent percentage change in production. We estimated a 0.09 percent increase in energy imports. For more information on the estimated energy effects, please refer to the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011).'' The analysis is available in the public docket. While we did not redo the RIA for this proposed action, the energy impacts for existing sources decreased slightly, and the energy impacts for new source increased due to the increased number of new sources that is now projected. Overall, the projected energy use increased slightly but would not change the analysis that was conducted for the final rule. Therefore, we conclude that the proposed rule when implemented is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement

Act of 1995 (NTTAA), Public Law 104–113,(15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the agency decides not use available and applicable voluntary consensus standards. The EPA is not proposing the use of any additional EPA test methods, and, therefore, the NTTAA discussion in the March 21, 2011, final rule is still valid. *See* 76 FR 15660–15662.

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. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

For the March 2011 final rule, the EPA determined that rule would 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 or low-income population. Compared to the final rule, while the proposed amendments are somewhat less stringent for some subcategories of units and more stringent for some others, the overall increased health benefits demonstrate that the conclusions from the environmental justice analysis conducted for the final rule are still valid.

List of Subjects in 40 CFR Part 63

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

Dated: December 2, 2011.

Lisa P. Jackson,

Administrator.

For the reasons cited in the preamble, and under the authority of 42 U.S.C. 7401 *et seq.,* Subpart DDDDD of 40 CFR part 63 is proposed to be revised to read as follows:

PART 63—[AMENDED]

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

Sec.

What This Subpart Covers

§ 63.7480 What is the purpose of this subpart?

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

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in

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

§ 63.7490 What is the affected source of this subpart?

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

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

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

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

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

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

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

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

(a) An electric utility steam generating unit.

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

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

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

(e) A refining kettle covered by subpart X of this part.

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

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

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

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60 or part 61 of this chapter provided that at least 50 percent of the heat input to the boiler or process heater is provided by the gas stream that is regulated under another subpart.

(j) Temporary boilers as defined in this subpart.

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

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

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.

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

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by [*DATE 60 DAYS AFTER THE FINAL RULE IS PUBLISHED IN THE* **Federal Register**] or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than [*DATE 3 YEARS AFTER PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**], except as provided in § 63.6(i).

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

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

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

(d) You must meet the notification requirements in § 63.7545 according to the schedule in § 63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

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

Emission Limitations and Work Practice Standards

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

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

(a) Pulverized coal/solid fossil fuel units.

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

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

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(e) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

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

(g) Suspension burners designed to burn biomass/bio-based solid.

(h) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(i) Fuel cells designed to burn biomass/bio-based solid.

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

(k) Units designed to burn solid fuel.

(l) Units designed to burn liquid fuel.

(m) Units designed to burn heavy liquid fuel.

(n) Units designed to burn light liquid fuel.

(o) Units designed to burn liquid fuel in non-continental states or territories.

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

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

(r) Metal process furnaces.

(s) Limited-use boilers and process heaters.

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

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

(1) You must meet each emission limit and work practice standard in

Tables 1 through 3 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. The output-based emission limits (*i.e.,* in units of pounds per million Btu of steam output) in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate steam. The output-based emission limits are not applicable to process heaters that do not generate steam.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

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

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

(d) Boilers and process heaters with a heat input capacity of less than 5 million Btu per hour in the units designed to burn natural gas, refinery gas or other gas 1 fuels subcategory; units designed to burn gas 2 (other) fuels subcategory, or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540.

(e) These standards apply at all times, except during periods of startup and shutdown, during which time you must comply only with Table 3 to this subpart.

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

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

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

(1) The excess emissions:

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

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

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

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

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

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

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

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

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

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

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

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

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

General Compliance Requirements

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

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times except for the periods noted in § 63.7500(e).

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emissions monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride, mercury, or total selected metals using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the total selected metals alternative standard or the hydrogen chloride standard.) Otherwise, you must demonstrate compliance for hydrogen chloride, mercury, or total selected metals using performance testing, if subject to an applicable emission limit listed in Table 1 or 2 to this subpart.

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

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the delegated authority for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and COMS prepared under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

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

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

(iii) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations, accuracy audits, analytical drift).

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

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

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

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 10 to this subpart), (e)(1), and (e)(2)(i).

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

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

Testing, Fuel Analyses, and Initial Compliance Requirements

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

(a) For affected sources that are required to or elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 of this subpart through performance testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For affected sources that burn a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected sources that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those gaseous fuels are subject to another subpart of this part, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must still conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) through (iii) of this section.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to § 63.7525.

(b) For affected sources that elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 of this subpart for hydrogen chloride, mercury or total selected metals through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) through (iii) of this section are exempt from these fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or hydrogen chloride are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section.

(c) If your boiler or process heater is subject to a carbon monoxide limit, your initial compliance demonstration for carbon monoxide is to conduct a performance test for carbon monoxide according to Table 5 to this subpart, or conduct a performance evaluation of your continuous carbon monoxide monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a continuous emission monitoring system for carbon monoxide are exempt from the initial carbon monoxide performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater subject to a PM limit has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or residual oil, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart. Owners of boilers and process heaters who elect to comply with the alternative total selected metals limit are not required to install a CPMS.

(e) For existing affected sources, you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and complete the one-time energy assessment specified in Table 3 to this subpart, both no later than the compliance date specified in § 63.7495.

(f) For new or reconstructed affected sources, you must complete the initial compliance demonstration with the emission limits no later than [*DATE 240 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**] or within 180 days after startup of the source, whichever is later.

(g) For new or reconstructed affected sources, you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart no later than the compliance date that is specified in § 63.7595 and according to the applicable provisions in § 63.7(a)(2). You must conduct the initial tune-up within 365 days after startup of the source. Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7540(a).

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

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

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e) of this section.

(b) You can conduct performance tests less often for a given pollutant if your performance tests for the pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 to this subpart, at or below the emission limit) and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions. In this case, you do not have to conduct a performance test for that pollutant for the next 2 years. You must conduct a performance test during the third year and no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually.

(c) If your boiler or process heater continues to meet the emission limit for the pollutant, you may choose to conduct performance tests for the pollutant every third year if your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 to this subpart, at or below the emission limit) and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions, but each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for hydrogen chloride. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum total selected metals input level is waived unless the stack test is conducted for total selected metals.

(d) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (either 75 percent of the emission or the emission limit, as specified in Tables 1 and 2).

(e) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source, the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(f) If you demonstrate compliance with the mercury, hydrogen chloride, or total selected metals based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1 or 2 to this subpart. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If 12 consecutive monthly fuel analyses demonstrate compliance, you may request decreased fuel analysis frequency by applying to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(g) You must report the results of performance tests and the associated initial fuel analyses within 90 days after the completion of the performance tests. This report must also verify that the operating limits for your affected source have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

§ 63.7520 What stack tests and procedures must I use?

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

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

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and total selected metals if you are opting to comply with the total selected metals alternative standard, and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 to this subpart.

(e) To determine compliance with the emission limits, you must use the F–Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A–7 of this chapter to convert the measured particulate matter concentrations, the measured hydrogen chloride concentrations, the measured mercury concentrations, and the measured total selected metals concentrations that result from the initial performance test to pounds per million Btu heat input emission rates using F-factors.

§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels, you must also conduct fuel analyses for total selected metals if you are opting to comply with the total selected metals alternative standard. For gas 2 (other) fuels, you must conduct fuel analysis for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the total selected metals alternative standard or the hydrogen chloride standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. 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, hydrogen chloride, or total selected metals in Tables 1 and 2 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 of this subpart.

(b) You must develop and submit a site-specific fuel monitoring plan to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

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

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing. For monthly sampling, each composite sample shall be collected at approximately equal 10-day intervals during the month.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (*e.g.,* larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or total selected metals) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (3) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

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

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

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

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each gas 1 fuel type according to the procedures in Table 6 to this subpart.

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

(a) As an alternative to meeting the requirements of § 63.7500 for particulate matter, hydrogen chloride, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategory located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average particulate matter, hydrogen chloride, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may not include in an average units using a CEMS or PM CPMS for demonstrating compliance, even if the use of a CEMS or PM CPMS is optional.

(2) For Hg and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the liquid, solid fuel, and gas 2 (other) subcategories.

(3) For particulate matter, averaging is only allowed between units within each of the following combustor level subcategories and you may not average across subcategories:

(i) Pulverized coal/solid fossil fuel units.

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

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

(iv) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(v) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

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

(vii) Suspension burners designed to burn biomass/bio-based solid.

(viii) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

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

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

(xi) Units designed to burn heavy liquid fuel.

(xii) Units designed to burn light liquid fuel.

(xiii) Units designed to burn liquid fuel in non-continental states or territories.

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

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on [*DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**] or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on [*DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**].

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified in § 63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1a or 1b of this section to demonstrate that the particulate matter, hydrogen chloride, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis and use Equation 1b if you are complying with the emission limits on a steam generation (output) basis.

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

Where:

AveWeightedEmissions = Average weighted emissions for particulate matter, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

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

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq.1b)}$$

Where:

AveWeightedEmissions = Average weighted emissions for particulate matter, hydrogen chloride, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in § 63.7575.

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

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the particulate matter, hydrogen chloride, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

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

Where:

AveWeightedEmissions = Average weighted emission level for PM, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.

Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.7495.

(1) For each calendar month, you must use Equation 3a or 3b of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you

are complying with the emission limits on a steam generation (output) basis.

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

Where:

AveWeightedEmissions = Average weighted emission level for particulate matter, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).

Hb = The heat input for that calendar month to unit, i, in units of million Btu.

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

1.1 = Required discount factor.

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

Where:

AveWeightedEmissions = Average weighted emission level for particulate matter, hydrogen chloride, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.

So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in § 63.7575.

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

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

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

Where:

AveWeightedEmissions = average weighted emission level for PM, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

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

Where:

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

ERi = Monthly weighted average, for calendar month “i” (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

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

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

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

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of *[DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**] and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

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

(v) The operating parameters to be monitored for each control system or device consistent with § 63.7500 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to § 63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the applicable delegated authority, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) The delegated authority shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable delegated authority shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategory.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average particulate matter, hydrogen chloride, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in § 63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

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

Where:

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

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

Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified in § 63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in § 63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategory subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

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

(a) If your boiler or process heater is subject to a carbon monoxide emission limit in Table 1 or 2 to this subpart, you must install, operate, and maintain an oxygen analyzer system as defined in § 63.7575, or a carbon monoxide continuous emission monitoring system (CO CEMS) according to the procedures in paragraphs (a)(1) through (10) of this section.

(1) The oxygen analyzer system or the CO CEMS must be installed by the compliance date specified in § 63.7495. If a CO CEMS is used, the carbon monoxide level shall be monitored at the outlet of the boiler or process heater.

(2) You must operate the oxygen trim system with the oxygen level set at the minimum percent oxygen by volume that is established as the operating limit for oxygen according to Table 4 to this subpart.

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

(4) For a new unit, the initial performance evaluation shall be completed no later than [*DATE 240 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**] or 180 days after the date of initial startup, whichever is later. For an

existing unit, the initial performance evaluation shall be completed no later than [*DATE 3 YEARS AND 180 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**].

(5) You must conduct a performance evaluation of each CO CEMS according to the requirements in § 63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B. During each relative accuracy test run of the CO CEMS, emission data for carbon monoxide must be collected concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A–4. The relative accuracy testing must be at representative operating conditions.

(6) For each CO CEMS, you must follow the quality assurance procedures (*e.g.,* quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(7) Each CO CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect at least four CO CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

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

(9) You must calculate one-hour arithmetic averages, corrected to 3 percent oxygen from each hour of CO CEMS data in parts per million carbon monoxide concentration. For all subcategories except for units designed to burn liquid fuels in non-continental states and territories, the one-hour arithmetic averages required shall be used to calculate the boiler operating day daily arithmetic average emissions. Calculate a 10-day rolling average from the daily averages. For units designed to burn liquid fuels in non-continental states and territories, the one-hour arithmetic averages required shall be used to calculate the 3-hour arithmetic average emissions. Use Equation 19–19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A–7 for calculating the average carbon monoxide concentration from the hourly values.

(10) For purposes of collecting CO data, you must operate the CO CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(b) If your boiler or process heater has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or residual oil, and you demonstrate compliance with the PM limit instead of the alternative total selected metals limit, you must install, certify, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. For other boilers or process heaters, you may elect to use a PM CPMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (*e.g.,* bag leak detectors, ESP secondary power, PM scrubber pressure).

(1) Install, certify, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

(ii) The PM CPMS must have a cycle time (*i.e.,* period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable of detecting and responding to particulate matter concentrations of no greater than 0.5 milligram per actual cubic meter.

(2) For a new unit, complete the initial performance evaluation no later than [*DATE 240 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**] or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than [*DATE 3 YEARS AND 180 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**].

(3) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in § 63.7535(a) through (d). Express the PM CPMS output as millamps, PM concentration, or other raw data signal value.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler operating hours (*e.g.,* milliamps, PM concentration, raw data signal).

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

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

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

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

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

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

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

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

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

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

(2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in paragraph (d)(3) of this section.

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

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

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

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the expected flow rate.

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

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

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

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

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

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

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

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

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

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

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

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

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

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than quarterly.

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

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

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

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

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

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

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

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

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

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

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

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

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

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

(l) For each unit for which you decide to demonstrate compliance with the mercury or hydrogen chloride emissions limits in Tables 1 or 2 of this subpart by use of a CEMS for mercury or hydrogen chloride, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For hydrogen chloride, this option for an affected unit takes effect on the date a final performance specification for a hydrogen chloride CEMS is published in the **Federal Register** or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(14) for a mercury CEMS and § 63.7540(a)(15) for a hydrogen chloride CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than [*DATE 240 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**].

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than [*DATE 3 YEARS AND 180 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**].

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A–7, but substituting the mercury or hydrogen chloride concentration for the pollutant concentrations normally used in Method 19.

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

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

(8) If you are using an add-on control to comply with the mercury or hydrogen chloride emission limit, you are allowed to substitute the use of the mercury or hydrogen chloride CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the mercury or hydrogen chloride emissions limit.

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

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

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or total selected metals input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

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

Where:

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

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

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

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

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

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

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

Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

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

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

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

(3) If you opt to comply with the alternative total selected metals limit, you must establish the maximum total selected metals fuel input (TSMinput) for solid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of total selected metals.

(ii) During the fuel analysis for total selected metals, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of total selected metals, and the average total selected metals concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum total selected metals input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} \left(TSMi \times Qi\right) \qquad \text{(Eq. 9)}$$

Where:

TSMinput = Maximum amount of total selected metals entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of total selected metals in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of total selected metals. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

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

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (vii) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for hydrogen chloride and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the hydrogen chloride performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (*e.g.,* ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your operating limit during the three-run performance during which you demonstrate compliance with your applicable limit. The PM CPMS operating limit is the 1-hour average PM CPMS output value recorded during the performance test. If you conduct separate performance tests for PM and total selected metals, you must set the maximum PM CPMS operating limits at the lower of maximum PM CPMS values established during the performance tests.

(iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for particulate matter and total selected metals emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the hydrogen chloride performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iv) For an electrostatic precipitator operated with a wet scrubber, you must establish the minimum voltage and secondary amperage (or total power input), as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to electrostatic precipitators that are operated as dry controls without a wet scrubber.)

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

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

(vii) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel

pollutant concentration of the composite samples analyzed for each fuel type using the one-sided z-statistic test described in Equation 10 of this section.

$$P90 = mean + (SD \times t) \quad \text{(Eq. 10)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

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

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

T = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for hydrogen chloride, the hydrogen chloride emission rate that you calculate for your boiler or process heater using Equation 11 of this section must not exceed the applicable emission limit for hydrogen chloride.

$$HCl = \sum_{i=1}^{n} (Ci90 \times Qi \times 1.028) \quad \text{(Eq. 11)}$$

Where:

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

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 10 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

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

1.028 = Molecular weight ratio of hydrogen chloride to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 12 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} (Hgi90 \times Qi) \quad \text{(Eq. 12)}$$

Where:

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

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 10 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

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

(5) To demonstrate compliance with the applicable emission limit for total selected metals for solid fuels, the total selected metals emission rate that you calculate for your boiler or process heater from solid fuels using Equation 13 of this section must not exceed the applicable emission limit for total selected metals.

$$Metals = \sum_{i=1}^{n} (TSM90i \times Qi) \quad \text{(Eq. 13)}$$

Where:

Metals = Total selected metals emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of total selected metals in fuel, i, in units of pounds per million Btu as calculated according to Equation 10 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest total selected metals content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

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

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

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility.

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

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of an other gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i). If the mercury constituents in the gaseous fuels will never exceed the specification included in the definition, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels. If your gas constituents could vary above the specification, you will conduct monthly testing according to the procedures in § 63.7521(f) through (i) and § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g).

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. You must submit a signed statement in the Notification of Compliance Status report that indicates that you employed good combustion practices and you maintained oxygen concentrations as specified by the boiler manufacturer for each startup and shutdown event.

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

(a) If you elect to comply with the alternative equivalent steam output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using emission reduction credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the emission credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the emission credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler.

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

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

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

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

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, *etc.* If possible, use actual data that are current and timely rather than estimated data.

(c) Emissions credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

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

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

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

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

(i) Calculate annual credits for all energy demand points. Use Equation 14 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 14 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual} \right) \div EI_{baseline} \qquad \text{(Eq. 14)}$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the emissions credit for the affected boiler.

(d) The owner or operator shall develop and submit for approval an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an emissions credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the emissions credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. You must submit the implementation plan for emission credits to the applicable delegated authority for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the emission credit approach.

(e) The emissions rate as calculated using Equation 15 of this section from each existing boiler participating in the emissions credit option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified in § 63.7495.

(f) You must use Equation 15 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the emissions credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 15)}$$

Where:

E_{adj} = Emission level adjusted by applying the emission credits earned, lb per million Btu steam output for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output for the affected boiler.

ECredits = Emission credits from Equation 14 for the affected boiler.

Continuous Compliance Requirements

§ 63.7535 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected source is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. 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 complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (17) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.7550(c), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Lower emissions of hydrogen chloride, mercury, and total selected metals than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Lower fuel input of chlorine, mercury, and total selected metals than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable hydrogen chloride emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the hydrogen chloride emission rate using Equation 11 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to complete fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the hydrogen chloride emission rate.

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

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

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

(4) If you demonstrate compliance with an applicable hydrogen chloride emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the hydrogen chloride emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to complete fuel analyses for and include the fuels described in § 63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 12 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this

section. You are not required to complete fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

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

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

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 12 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 of § 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to complete fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

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

(i) Continuously monitor CO according to §§ 63.7525(a) and 63.7535.

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

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

(9) The owner or operator of an affected source using a PM CPMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

(10) If your boiler or process heater is in either the natural gas, refinery gas, other gas 1, or Metal Process Furnace subcategories and has a heat input capacity of 10 million Btu per hour or greater, you must conduct a tune-up of the boiler or process heater annually to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This requirement does not apply to limited-use boilers and process heaters, as defined in § 63.7575.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled or unscheduled unit shutdown);

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

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

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

(v) Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made); and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of carbon monoxide in the effluent stream in parts per million by volume, and oxygen in volume percent, measured before and after the adjustments of the boiler;

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

(C) The type and amount of fuel used over the 12 months prior to the annual adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a heat input capacity of less than 5 million Btu per hour, and the unit is in the units designed to burn natural gas, refinery gas or other gas 1 fuels, units designed to burn gas 2 (other), or units designed to burn light liquid subcategories, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

(13) 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.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be a calendar month. For each calendar month in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure hydrogen chloride emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the hydrogen chloride CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for a hydrogen chloride CEMS is published in the **Federal Register** or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be a calendar month. For each calendar month in which the unit operates, you must obtain hourly hydrogen chloride concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a hydrogen chloride continuous emissions monitoring system, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the hydrogen chloride mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable total selected metals emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum total selected metals input using Equation 9 of § 63.7530. If the results of recalculating the maximum total selected metals input using Equation 9 of § 63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the total selected metals emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to complete fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the total selected metals emission rate.

(17) If you demonstrate compliance with an applicable total selected metals emission limit through fuel analysis for solid fuels, and you plan to burn a new type of fuel, you must recalculate the total selected metals emission rate using Equation 13 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to complete fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the total selected metals emission rate.

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

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

(iii) Recalculate the total selected metals emission rate from your boiler or process heater under these new conditions using Equation 13 of § 63.7530. The recalculated total selected metals emission rate must be less than the applicable emission limit.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the other gas 1 subcategory and you cannot submit a signed certification under § 63.7545(g) because the constituents could exceed the specification, you must conduct monthly fuel specification testing of the gaseous fuels, according to the procedures in § 63.7521(f) through (i).

(d) For periods of startup and shutdown, you must meet the work practice standards according to Table 3 of this subpart.

§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.7522(f) and (g).

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

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

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

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or below the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating plan, maintain the 30-day rolling average parameter values at or below the operating limits established in the most recent performance test.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

Notification, Reports, and Records

§ 63.7545 What notifications must I submit and when?

(a) You must submit to the delegated authority all of the notifications in § 63.7(b) and (c), § 63.8(e), (f)(4) and (6), and § 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before [*DATE 60 DAYS AFTER THE DATE OF PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**], you must submit an Initial Notification not later than 120 days after [*DATE 60 DAYS AFTER THE DATE OF PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**].

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after [*DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER*], you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

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

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each affected source, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for the affected source according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable.

(1) A description of the affected unit(s) including identification of which subcategory the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under § 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of § 241.3, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) A summary of the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable emission standard in Table 1 or 2 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

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

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using emission credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on [*DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **Federal Register**].

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

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) ''This facility complies with the requirements in § 63.7540(a)(10), (11), or (12) to conduct an annual, biennial, or 5-year tune-up, as applicable, of each unit.''

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

(iii) Except for units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: ''No secondary materials that are solid waste were combusted in any affected unit.''

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

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

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

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

(g) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(h) If you intend to switch fuels, and this fuel switch may result in the applicability of a different subcategory, you must provide 30 days prior notice of the date upon which you will switch fuels. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that will switch fuels, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable standards.

(4) The date upon which you will commence the fuel switch.

§ 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section. For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (5) of this section, instead of a semi-annual compliance report.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in § 63.7495.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked no later than January 31.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the delegated authority has established dates for submitting semiannual reports pursuant to § 70.6(a)(3)(iii)(A) or § 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the delegated authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (13) of this section.

(1) Company name and address.

(2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual (or annual, biennial, or 5-year) reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(5) A summary of the results of the annual performance tests for affected sources subject to an emission limit, a summary of any fuel analyses associated with performance tests, and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests, a comparison of the emission level you achieved in the last 2 performance tests to the 75 percent emission limit threshold required in § 63.7515(b) or (c), and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(6) A signed statement indicating that you burned no new types of fuel in an affected source subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a hydrogen chloride emission limit, you must submit the calculation of chlorine input, using Equation 5 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of hydrogen chloride emission rate using Equation 11 of § 63.7530 that demonstrates that your source is still meeting the emission limit for hydrogen chloride emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 12 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a total selected metals emission limit, you must submit the calculation of total selected metals input, using Equation 9 of § 63.7530, that demonstrates that your source is still within its maximum total selected metals input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of total selected metals emission rate, using Equation 13 of § 63.7530, that demonstrates that your source is still meeting the emission limit for total selected metals emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(7) If you wish to burn a new type of fuel in an affected source subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum total selected metals input operating limit using Equation 9 of § 63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(8) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for affected sources subject to emission limits, and any fuel specification analyses conducted according to § 63.7521(f) and § 63.7530(g).

(9) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(10) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and continuous parameter monitoring systems, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(11) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of

actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(12) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(13) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(14) For units subject to emission limits in Tables 1 or 2 of this subpart, for each startup or shutdown event during the reporting period, report the percentage concentration of oxygen in the firebox on an hourly basis throughout the event, the calendar date and length of each event, and the reason for each event.

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an affected source where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (4) of this section.

(1) The total operating time of each affected source during the reporting period.

(2) A description of the deviation and which emission limit or operating limit from which you deviated.

(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(4) A copy of the test report if the annual performance test showed a deviation from the emission limits.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in paragraphs (e)(1) through (12) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (*i.e.,* what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) An analysis of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) An identification of each parameter that was monitored at the affected source for which there was a deviation.

(9) A brief description of the source for which there was a deviation.

(10) A brief description of each CMS for which there was a deviation.

(11) The date of the latest CMS certification or audit for the system for which there was a deviation.

(12) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by § 70.6(a)(3)(iii)(A) or § 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 9 to this subpart along with, or as part of, the semiannual monitoring report required by § 70.6(a)(3)(iii)(A) or § 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the delegated authority.

(g) (Reserved)

(h) Within 60 days after the date of completing each performance test, you must transmit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(i) Within 60 days after the date of completing each CEMS (CO and Hg) performance evaluation test, as defined in § 63.2 and required by this subpart, you must submit the relative accuracy test audit data electronically into EPA's Central Data Exchange by using the Electronic Reporting Tool as described in paragraph (h) of this section. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically to EPA's CDX.

(j) Within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, you must transmit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). For each reporting period, the quarterly reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and Hg) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

§ 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

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

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

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

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

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

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Table 1 or 2 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (9) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) and (2), you must keep a record that 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 satisfy 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. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) You must keep records of monthly hours of operation by each boiler or process heater that meets the definition of limited-use boiler or process heater.

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

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 12 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(6) If, consistent with § 63.7515(b) and (c), you choose to stack test less frequently than annually, you must keep annual records that document that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

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

(8) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(9) A copy of all calculations and supporting documentation of maximum total selected metals fuel input, using Equation 9 of § 63.7530, that were done to demonstrate continuous compliance with the total selected metals emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of total selected metals emission rates, using Equation 13 of § 63.7530, that were done to demonstrate compliance with the total selected metals emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum total selected metals fuel input or total selected metals emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate total selected metals fuel input, or total selected metals emission rates, for each boiler and process heater.

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

(f) If you elect to use emission credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the other gas 1 subcategory and you cannot submit a signed certification under § 63.7545(g) because the constituents could exceed the specification, you must maintain monthly records of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuel that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, or other gas 1 fuel, you must keep records of the total hours per calendar year that alternative fuel is burned.

(i) For each startup or shutdown event, you must maintain records that boiler operators have completed training for startup and shutdown procedures.

§ 63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.7500(a) and (b) under § 63.6(g).

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

(3) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, and alternative analytical methods requested under § 63.7521(b)(2).

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

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

§ 63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2 (the General Provisions), and in this section as follows:

30-day rolling average means the arithmetic mean of all valid data from 30 successive operating days that is calculated for each operating day using the data from that operating day and the previous 29 operating days.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Average annual heat input rate means annual heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

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

Benchmarking means a process of comparison against standard or average.

Biodiesel means a mono-akyl ester derived from biomass and conforming to ASTM D6751–08, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

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

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel are excluded from this definition.

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

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of ''coal'' includes synthetic fuels derived from coal for creating useful heat, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

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

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight).

Deviation. (1) Means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM D396 (incorporated by reference, see § 63.14).

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

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Electric utility steam generating unit means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be ''capable of combusting'' fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (*e.g.,* coal handling equipment, including coal storage area, belts and conveyers, pulverizers, *etc.;* oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after [COMPLIANCE DATE OF THE FINAL EGU RULE].

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

Emission credit means emission reductions above those required by this subpart. Emission credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Shutdowns cannot be used to generate credits.

Energy assessment means the following only as this term is used in Table 3 to this subpart.

(1) Energy assessment for facilities with affected boilers and process heaters using less than 0.3 trillion Btu per year heat input will be 8 technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. 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 an 8-hour energy assessment.

(2) The Energy assessment for facilities with affected boilers and process heaters using 0.3 to 1.0 trillion Btu per year will be 24 technical labor hours in length maximum, but may be longer at the discretion of the owner or operator. 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 24-hour energy assessment.

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

Energy management practices means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

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

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

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an ''as received'' basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, hydrogen chloride) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

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

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

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

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

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

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, *etc.*

Heavy Liquid includes residual oil and any other liquid fuel not classified as a light liquid.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210 degrees Fahrenheit (99 degrees Celsius). Hot water boilers (*i.e.,* not generating steam) combusting gaseous or liquid fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. *Hot water heater* also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The fuel combusted in these units exceed a moisture content of 40 percent on an as-fired basis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

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

Light liquid includes distillate oil, biodiesel or vegetable oil.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable limit of no more than 876 hours per year of operation.

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

Load fraction means the actual heat input of the boiler or process heater divided by the average operating load determined according to Table 7 to this subpart.

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

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction (percent) multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Minimum pressure drop means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (*e.g.,* to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means load fraction (percent) multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); or

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

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

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

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed the maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas or firebox. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or carbon monoxide monitor that automatically provides a feedback signal to the combustion air controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel 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 due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters include units heating hot water as a process heat transfer medium. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel are excluded from this definition.

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

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Residential boiler means a boiler used in a dwelling containing four or fewer family units to provide heat and/or hot water. This definition includes boilers used primarily to provide heat and/or hot water for a dwelling containing four or fewer families located at an institutional facility (*e.g.,* university campus, military base, church grounds) or commercial/industrial facility (*e.g.,* farm).

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined in ASTM D396–10 (incorporated by reference, see § 63.14(b)).

Responsible official means responsible official as defined in § 70.2.

Shutdown means the period that begins when a unit last operates at 25 percent load and ending with a state of no fuel combustion in the unit.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

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

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means the period between the state of no combustion in the unit to the period where the unit first achieves 25 percent load (*i.e.,* a cold start).

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output;

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour) and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be calculated using Equations 16 through 20 of this section, as appropriate:

(i) For emission limits for boilers in the solid fuel subcategory use Equation 16 of this section:

$$EL_{OBE} = EL_T \times 12.7 \text{ MMBtu/Mwh} \quad \text{(Eq. 16)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(ii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal use Equation 17 of this section:

$$EL_{OBE} = EL_T \times 12.2 \text{ MMBtu/Mwh} \quad \text{(Eq. 17)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass use Equation 18 of this section:

$$EL_{OBE} = EL_T \times 13.9 \text{ MMBtu/Mwh} \quad \text{(Eq. 18)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iv) For emission limits for boilers in the one of the subcategories of units designed to burn liquid fuels use Equation 19 of this section:

$$EL_{OBE} = EL_T \times 13.8 \text{ MMBtu/Mwh} \quad \text{(Eq. 19)}$$

Where:

ELOBE = Emission limit in units of pounds per megawatt-hour.

ELT = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(v) For emission limits for boilers in the Gas 2 subcategory use Equation 20 of this section:

$$EL_{OBE} = EL_T \times 10.4 \text{ MMBtu/Mwh} \quad \text{(Eq. 20)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_{T} = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/ other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture.

Suspension burner means a unit designed to feed the fuel by means of fuel distributors. The distributors inject air at the point where the fuel is introduced into the boiler in order to spread the fuel material over the boiler width. The drying (and much of the combustion) occurs while the material is suspended in air. The combustion of the fuel material is completed on a grate or floor below. Suspension boilers almost universally are designed to have high heat release rates to dry quickly the wet fuel as it is blown into the boilers. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location for more than 12 consecutive months. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Total selected metals means the combination of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

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

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels; with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment and gas supply emergencies.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, less than 10 percent biomass/bio-based solid fuel, and less than 10 percent liquid fuels on an annual heat input basis.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

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

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater designed to burn liquid fuel located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards or VCS mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, *http://www.asme.org*), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm*), Standards Australia (AS Level 10, The

Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 *http://www.stadards.org.au*), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, *http://www.bsigroup.com*), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, (800) 463–6727, *http://www.csa.ca*), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B–1000 Brussels, Belgium +32 2 550 08 11, *http://www.cen.eu/cen*), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214–230, *http://www.vdi.eu*). The types of standards that are not considered VCS are standards developed by: the United States, *e.g.,* California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.,* Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. This definition includes both fired and unfired waste heat boilers.

Waste heat process heater means an enclosed device that recovers normally unused energy and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

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

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

Tables to Subpart DDDDD of Part 63

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

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

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

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. Hydrogen Chloride	0.022 lb per MMBtu of heat input.	0.025 lb per MMBtu of steam output or 0.28 lb per MWh.	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run
	b. Mercury	8.60E–07 lb per MMBtu of heat input.	9.4E–07 lb per MMBtu of steam output or 1.1 E–05 lb per MWh.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	9 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (28 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.0074 lb per MMBtu of steam output or 0.092 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 20 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.0013 lb per MMBtu of heat input; or (2.8E–05 [a] lb per MMBtu of heat input).	0.0013 lb per MMBtu of steam output or 0.016 lb per MWh; or (2.8E–05 [a] lb per MMBtu of steam output or 3.5E–04 [a] lb per MWh).	Collect a minimum of 3 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	19 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (34 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.017 lb per MMBtu of steam output or 0.20 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 30 ppmv for Method 10.

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

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

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable Particulate Matter (or Total Selected Metals).	0.028 lb per MMBtu of heat input; or (2.2E–05 [a] lb per MMBtu of heat input).	0.028 lb per MMBtu of steam output or 0.35 lb per MWh; or (3.0E–05 [a] lb per MMBtu of steam output or 2.7E–04 [a] lb per MWh).	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	17 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (59 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.015 lb per MMBtu of steam output or 0.18 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 40 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.0011 lb per MMBtu of heat input; or (1.7E–05 [a] lb per MMBtu of heat input).	0.0012 lb per MMBtu of steam output or 0.014 lb per MWh; or (1.8E–05 [a] lb per MMBtu of steam output or 2.1E–04 [a] lb per MWh).	Collect a minimum of 4 dscm per run.
5. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	590 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.56 lb per MMBtu of steam output or 6.5 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 600 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.029 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	0.034 lb per MMBtu of steam output or 0.41 lb per MWh; or (2.7E–05 lb per MMBtu of steam output or 3.7E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
6. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	250 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.23 lb per MMBtu of steam output or 2.8 lb per MWh.	1 hr minimum sampling time, use a span value of 400 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.32 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	0.37 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.2E–03 lb per MMBtu of steam output or 0.056 lb per MWh).	Collect a minimum of 2 dscm per run.
7. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (180 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.22 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 400 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.0098 lb per MMBtu of heat input; or (4.2E–05 [a] lb per MMBtu of heat input).	0.012 lb per MMBtu of steam output or 0.14 lb per MWh; or (5.4E–05 [a] lb per MMBtu of steam output or 5.9E–04 [a] lb per MWh).	Collect a minimum of 3 dscm per run.

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

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

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits . . .	Using this specified sampling volume or test run duration . . .
8. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	58 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (1,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.046 lb per MMBtu of steam output or 0.64 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 100 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.051 lb per MMBtu of heat input; or (1.1E–03 lb per MMBtu of heat input).	0.052 lb per MMBtu of steam output or 0.71 lb per MWh; or (0.0012 lb per MMBtu of steam output or 0.016 lb per MWh).	Collect a minimum of 1 dscm per run.
9. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (440 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.89 lb per MMBtu of steam output or 8.9 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 1000 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.036 lb per MMBtu of heat input; or (4.1E–05 lb per MMBtu of heat input).	0.050 lb per MMBtu of steam output or 0.51 lb per MWh; or (5.5E–05 lb per MMBtu of steam output or 5.8E–04 lb per MWh).	Collect a minimum of 1 dscm per run.
10. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	210 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.29 lb per MMBtu of steam output or 2.3 lb per MWh.	1 hr minimum sampling time, use a span value of 500 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.011 lb per MMBtu of heat input; or (4.9E–05 [a] lb per MMBtu of heat input).	0.030 lb per MMBtu of steam output or 0.16 lb per MWh; or (8.6E–05 [a] lb per MMBtu of steam output or 6.9E–04 [a] lb per MWh).	Collect a minimum of 1 dscm per run.
11. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (730 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1.80 lb per MMBtu of steam output or 17 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 3000 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.026 lb per MMBtu of heat input; or (4.9E–04 [a] lb per MMBtu of heat input).	0.033 lb per MMBtu of steam output or 0.37 lb per MWh; or (6.2E–04 [a] lb per MMBtu of steam output or 6.9E–03 [a] lb per MWh).	Collect a minimum of 3 dscm per run.
12. Units designed to burn liquid fuel.	a. Hydrogen Chloride	0.0012 lb per MMBtu of heat input.	0.0013 lb per MMBtu of steam output or 0.017 lb per MWh.	For M26A: Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	4.9E–07 [a] lb per MMBtu of heat input.	5.4E–07 [a] lb per MMBtu of steam output or 6.8E–06 [a] lb per MWh.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.

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

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

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits . . .	Using this specified sampling volume or test run duration . . .
13. Units designed to burn heavy liquid fuel.	a. CO (or CEMS)	10 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.0091 lb per MMBtu of steam output or 0.11 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 30 ppmv for Method 10.
	b. Filterable Particulate Matter.	0.013 lb per MMBtu of heat input.	0.015 lb per MMBtu of steam output or 0.18 lb per MWh.	Collect a minimum of 2 dscm per run.
14. Units designed to burn light liquid fuel.	a. CO (or CEMS)	3 ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, 1-day block average).	0.0031 lb per MMBtu of steam output or 0.033 lb per MWh.	1 hr minimum sampling time, use a span value of 10 ppmv for Method 10.
	b. Filterable Particulate Matter.	0.0011 [a] lb per MMBtu of heat input for light liquid.	0.0015 [a] lb per MMBtu of steam output or 0.016 lb per MWh.	Collect a minimum of 3 dscm per run.
15. Units designed to burn liquid fuel located in non-continental states and territories.	a. CO	18 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average based on CEM).	0.017 lb per MMBtu of steam output or 0.20 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 40 ppmv for Method 10.
	b. Filterable Particulate Matter.	0.0080 lb per MMBtu of heat input.	0.0087 lb per MMBtu of steam output or 0.11 lb per MWh.	Collect a minimum of 4 dscm per run.
16. Units designed to burn gas 2 (other) gases.	a. CO	4 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.005 lb per MMBtu of steam output or 0.031 lb per MWh.	1 hr minimum sampling time, use a span value of 10 ppmv for Method 10.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input.	0.0029 lb per MMBtu of steam output or 0.018 lb per MWh.	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	1.4E–05 lb per MMBtu of steam output or 8.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable Particulate Matter (or Total Selected Metals).	0.0067 lb per MMBtu of heat input; or (2.4E–04 lb per MMBtu of heat input).	0.012 lb per MMBtu of steam output or 0.070 lb per MWh; or (4.0E–04 lb per MMBtu of steam output or 0.0025 lb per MWh).	Collect a minimum of 1 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

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

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

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

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. Hydrogen Chloride	0.022 lb per MMBtu of heat input.	0.025 lb per MMBtu of steam output or 0.28 lb per MWh.	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	3.1E–06 lb per MMBtu of heat input.	3.5E–06 lb per MMBtu of steam output or 4.0E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	41 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (28 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.035 lb per MMBtu of steam output or 0.42 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 100 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.044 lb per MMBtu of heat input; or (5.9E–05 lb per MMBtu of heat input).	0.045 lb per MMBtu of steam output or 0.54 lb per MWh; or (6.0E–05 lb per MMBtu of steam output or 7.3E–04 lb per MWh).	Collect a minimum of 1 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	220 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (34 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.20 lb per MMBtu of steam output or 2.3 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 400 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.028 lb per MMBtu of heat input; or (8.3E–05 lb per MMBtu of heat input).	0.030 lb per MMBtu of steam output or 0.35 lb per MWh; or (8.8E–05 lb per MMBtu of steam output or 0.0011 lb per MWh).	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	56 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (59 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.049 lb per MMBtu of steam output or 0.57 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 100 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.088 lb per MMBtu of heat input; or (1.7E–05 lb per MMBtu of heat input).	0.092 lb per MMBtu of steam output or 1.1 lb per MWh; or (1.8E–05 lb per MMBtu of steam output or 2.1E–04 lb per MWh).	Collect a minimum of 1 dscm per run.

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

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

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits . . .	Using this specified sampling volume or test run duration . . .
5. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	790 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.72 lb per MMBtu of steam output or 8.7 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 1000 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.029 lb per MMBtu of heat input; or (5.7E–05 lb per MMBtu of heat input).	0.034 lb per MMBtu of steam output or 0.41 lb per MWh; or (6.6E–05 lb per MMBtu of steam output or 8.0E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
6. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	250 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.23 lb per MMBtu of steam output or 2.8 lb per MWh.	1 hr minimum sampling time, use a span value of 500 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.32 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	0.37 lb per MMBtu of steam output or 4.5 lb per MWh; or (0.0046 lb per MMBtu of steam output or 0.056 lb per MWh).	Collect a minimum of 1 dscm per run.
7. Fluidized bed units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	370 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (180 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.36 lb per MMBtu of steam output or 4.1 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 500 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.11 lb per MMBtu of heat input; or (0.0012 lb per MMBtu of heat input).	0.14 lb per MMBtu of steam output or 1.6 lb per MWh; or (0.0015 lb per MMBtu of steam output or 0.017 lb per MWh).	Collect a minimum of 1 dscm per run.
8. Suspension burners designed to burn biomass/bio-based solid.	a. CO (or CEMS)	58 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (1,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.046 lb per MMBtu of steam output or 0.64 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 100ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.051 lb per MMBtu of heat input; or (0.0011 lb per MMBtu of heat input).	0.052 lb per MMBtu of steam output or 0.71 lb per MWh; or (0.0012 lb per MMBtu of steam output or 0.016 lb per MWh).	Collect a minimum of 1 dscm per run.
9. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid.	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (440 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.89 lb per MMBtu of steam output or 8.9 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 1000 ppmv for Method 10.

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

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

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable Particulate Matter (or Total Selected Metals).	0.036 lb per MMBtu of heat input; or (2.4E–04 lb per MMBtu of heat input).	0.050 lb per MMBtu of steam output or 0.51 lb per MWh; or (3.4E–04 lb per MMBtu of steam output or 0.0034 lb per MWh).	Collect a minimum of 1 dscm per run.
10. Fuel cell units designed to burn biomass/bio-based solid.	a. CO	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen.	3.2 lb per MMBtu of steam output or 17 lb per MWh.	1 hr minimum sampling time, use a span value of 2000 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.033 lb per MMBtu of heat input; or (4.9E–05 lb per MMBtu of heat input).	0.090 lb per MMBtu of steam output or 0.46 lb per MWh; or (1.4E–04 lb per MMBtu of steam output or 6.9E–04 lb per MWh).	Collect a minimum of 1 dscm per run.
11. Hybrid suspension grate units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	3,900 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (730 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	3.9 lb per MMBtu of steam output or 43 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 5000 ppmv for Method 10.
	b. Filterable Particulate Matter (or Total Selected Metals).	0.44 lb per MMBtu of heat input; or (4.9E–04[a] lb per MMBtu of heat input).	0.55 lb per MMBtu of steam output or 6.2 lb per MWh; or (6.2E–04[a] lb per MMBtu of steam output or 6.9E–03[a] lb per MWh).	Collect a minimum of 1 dscm per run.
12. Units designed to burn liquid fuel.	a. Hydrogen Chloride	0.0012 lb per MMBtu of heat input.	0.0015 lb per MMBtu of steam output or 0.017 lb per MWh.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	2.6E–05 lb per MMBtu of heat input.	3.3E–05 lb per MMBtu of steam output or 3.6E–04 lb per MWh.	For M29, collect a minimum of 2 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784[b] collect a minimum of 2 dscm.
13. Units designed to burn heavy liquid fuel.	a. CO (or CEMS)	10 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	0.0091 lb per MMBtu of steam output or 0.11 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 20 ppmv for Method 10.
	b. Filterable Particulate Matter.	0.062 lb per MMBtu of heat input.	0.075 lb per MMBtu of steam output or 0.86 lb per MWh.	Collect a minimum of 1 dscm per run.
14. Units designed to burn light liquid fuel.	a. CO (or CEMS)	7 ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, 1-day block average).	0.0071 lb per MMBtu of steam output or 0.076 lb per MWh.	1 hr minimum sampling time, use a span value of 10 ppmv for Method 10.
	b. Filterable Particulate Matter.	0.0034 lb per MMBtu of heat input.	0.0045 lb per MMBtu of steam output or 0.047 lb per MWh.	Collect a minimum of 3 dscm per run.

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

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

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits . . .	Using this specified sampling volume or test run duration . . .
15. Units designed to burn liquid fuel located in non-continental states and territories.	a. CO (or CEMS)	18 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average based on CEM).	0.017 lb per MMBtu of steam output or 0.20 lb per MWh; 3-run average.	1 hr minimum sampling time, use a span value of 40 ppmv for Method 10.
	b. Filterable Particulate Matter.	0.0080 lb per MMBtu of heat input.	0.0097 lb per MMBtu of steam output or 0.11 lb per MWh.	Collect a minimum of 2 dscm per run.
16. Units designed to burn gas 2 (other) gases.	a. CO	4 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.0050 lb per MMBtu of steam output or 0.031 lb per MWh.	1 hr minimum sampling time, use a span value of 10 ppmv for Method 10.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input.	0.0029 lb per MMBtu of steam output or 0.018 lb per MWh.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	1.4E–05 lb per MMBtu of steam output or 8.3E–05 lb per MWh.	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 2 dscm.
	d. Filterable Particulate Matter (or Total Selected Metals).	0.0067 lb per MMBtu of heat input or (2.4E–04 lb per MMBtu of heat input).	0.012 lb per MMBtu of steam output or 0.070 lb per MWh; or (4.0E–04 lb per MMBtu of steam output or 0.0025 lb per MWh).	Collect a minimum of 1 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

As stated in § 63.7500, you must comply with the following applicable work practice standards:

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

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with heat input capacity of less than 5 million Btu per hour in any of the following subcategories: unit designed to burn natural gas, refinery gas or other gas 1 fuels; unit designed to burn gas 2 (other); or unit designed to burn light liquid.	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.
2. A limited use boiler or process heater; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but equal to or greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn natural gas, refinery gas or other gas 1 fuels; unit designed to burn gas 2 (other); or unit designed to burn light liquid.	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.

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

If your unit is . . .	You must meet the following . . .
3. A new or existing boiler or process heater with heat input capacity of 10 million Btu per hour or greater.	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility	Must have a one-time energy assessment performed on the major source facility by qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. The energy assessment must include: a. A visual inspection of the boiler or process heater system. b. An evaluation of operating characteristics of the facility, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints. c. An inventory of major systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator. d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices. f. A list of major energy conservation measures. g. A list of the energy savings potential of the energy conservation measures identified. h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new unit subject to emission limits in Tables 1 or 2 to this subpart.	You must employ good combustion practices and demonstrate that good combustion practices are maintained by monitoring O_2 concentrations and optimizing those concentrations as specified by the boiler manufacturer; you must ensure that boiler operators are trained in startup and shutdown procedures, including maintenance and cleaning, safety, control device startup, and procedures to minimize emissions; and you must maintain records during periods of startup and shutdown and include in your compliance reports the O_2 conditions/data for each event, length of startup/shutdown and reason for the startup/shutdown (*i.e.,* normal/routine, problem/malfunction, outage).

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

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

If you demonstrate compliance using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control on a boiler not using a PM CPMS.	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.
2. Wet acid gas (HCl) scrubber control on a boiler not using a hydrogen chloride CEMS.	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on units not using a PM CPMS.	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on units not using a PM CPMS.	a. This option is for boilers and process heaters that operate dry control systems (*i.e.,* an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (*i.e.,* COMS). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.

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

If you demonstrate compliance using . . .	You must meet these operating limits . . .
5. Dry scrubber or carbon injection control on a boiler not using a mercury CEMS.	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.
6. Any other add-on air pollution control type on units not using a PM CPMS.	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance test.
9. Oxygen Analyzer System	For boilers and process heaters subject to a carbon monoxide emission limit that demonstrate compliance with an O_2 analyzer system as specified in § 63.7525(a), maintain the oxygen level such that it is not below the lowest hourly average oxygen concentration measured during the most recent CO performance test.

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

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

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A–3 or A–6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
2. Hydrogen chloride	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the hydrogen chloride emission concentration.	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A–8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
3. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the mercury emission concentration.	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A–8 of this chapter or Method 101A at 40 CFR part 60, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
4. CO	a. Select the sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine oxygen concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–3 of this chapter, or ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981.[a]
	c. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.

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

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
	d. Measure the CO emission concentration.	Method 10 at 40 CFR part 60, appendix A–4 of this chapter. Use a span value of 2 times the concentration of the applicable emission limit.

[a] Incorporated by reference, see § 63.14.

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

TABLE 6—TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234/D2234M [a] (for coal) or EPA 1631 or EPA 1631E or ASTM D6323 [a] (for solid), or EPA 821–R–01–013 (for liquid or solid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B [a] (for solid samples), EPA SW–846–3020A [a] (for liquid samples), ASTM D2013/D2013M [a] (for coal), ASTM D5198 [a] (for biomass), or ASTME829 or EPA 3050 (for solid fuel), or EPA 821–R–01–013 (for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a] (for coal) or ASTM E711 [a] (for biomass), or ASTM D5864 for liquids and other solids, or ASTM D240 or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a], ASTM E871 [a], or ASTM D5864, or ASTM D240 or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 [a] (for coal), EPA SW–846–7471B [a] (for solid samples), or EPA SW–846–7470A [a] (for liquid samples), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content.	Equation 8 in § 63.7530.
	h. Calculate the mercury emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 12 in § 63.7530.
2. Hydrogen Chloride	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234/D2234M [a] (for coal) or ASTM D6323 [a] (for coal or biomass), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B [a] (for solid samples), EPA SW–846–3020A [a] (for liquid samples), ASTM D2013/D2013M [a] (for coal), or ASTM D5198 [a] (for biomass),or ASTM E829 (for solid fuel), or EPA 3050 or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a] (for coal) or ASTM E711 [a] (for biomass), ASTM D5864, ASTM D240 or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a] or ASTM E871 [a], or D5864, or ASTM D240 or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW–846–9250 [a], ASTM D6721 [a], ASTM D4208 (for coal), or EPA SW–846–5050 [a] or ASTM E776 [a] (for solid fuel), or EPA SW–846–9056 or SW–846–9076 (for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of hydrogen chloride per MMBtu of heat content.	Equation 7 in § 63.7530.
	h. Calculate the hydrogen chloride emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 11 in § 63.7530.
3. Mercury Fuel Specification for other gas 1 fuels.	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter.	ASTM D5954 [a], ASTM D6350 [a], ISO 6978–1:2003(E) [a], or ISO 6978–2:2003(E) [a], or equivalent.
4. Total Selected Metals for solid fuels.	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234/D2234M [a] (for coal) or ASTM D6323 [a] (for coal or biomass), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.

TABLE 6—TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS—Continued

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
	c. Prepare composited fuel samples	EPA SW–846–3050B [a] (for solid samples), EPA SW–846–3020A [a] (for liquid samples), ASTM D2013/D2013M [a] (for coal), ASTM D5198 [a] or TAPPI T266 (for biomass), or ASTM E829 (for solid fuel), or EPA 3050 or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a] (for coal) or ASTM E711 [a] (for biomass), or ASTM D5864 for liquids and other solids, or ASTM D240 or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a] or ASTM E871 [a], or D5864, or ASTM D240 or equivalent.
	f. Measure total selected metals concentration in fuel sample.	ASTM D3683, or ASTM D4606, or ASTM D6357 or EPA 200.8 or or EPA SW–846–6020, or EPA SW–846–6020A, or ASTM E885, or EPA SW–846–6010B, EPA 7060 or EPA 7060A (for arsenic only), or EPA SW–846–7740 (for selenium only),
	g. Convert concentrations into units of pounds of total selected metals per MMBtu of heat content.	Equations 9 in § 63.7530.
	h. Calculate the total selected metals emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 13 in § 63.7530.

[a] Incorporated by reference, see § 63.14.

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

TABLE 7—TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements . . .
1. Particulate matter, total selected metals, or mercury.	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to § 63.7530(b).	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the particulate matter or mercury performance test.	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests. (b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b).	(1) Data from the voltage and secondary amperage monitors during the particulate matter or mercury performance test.	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests. (b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
2. Hydrogen Chloride	a. Wet scrubber operating parameters.	i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b).	(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the hydrogen chloride performance test.	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests.

TABLE 7—TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements . . .
				(b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b) If different acid gas sorbents are used during the hydrogen chloride performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.	(1) Data from the sorbent injection rate monitors and hydrogen chloride or mercury performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (*e.g.,* for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. Mercury	a. Activated carbon injection.	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b).	(1) Data from the activated carbon rate monitors and mercury performance test.	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.

TABLE 7—TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements . . .
				(c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (*e.g.,* actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520.	(1) Data from the oxygen analyzer system specified in § 63.7525(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test.	a. Boiler or process heater operating load.	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c).	(1) Data from the operating load monitors or from steam generation monitors.	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

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

TABLE 8—TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.7525(c) and § 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. PM CPMS	a. Collecting the PM CPMS output data according to § 63.7525;

TABLE 8—TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE—Continued

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
	b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to § 63.7530.
3. Fabric Filter Bag Leak Detection Operation.	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(9) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to § 63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate.	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input.	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
8. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.7530(b) or (c) as applicable; and b. Keeping monthly records of fuel use according to § 63.7540(a).
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen trim system according to § 63.7525(a). b. Reducing the data to 30-day rolling averages; and c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent carbon monoxide performance test.
10. Carbon monoxide emissions.	a. Continuously monitor the carbon monoxide concentration in the combustion exhaust according to § 63.7525(a). b. Correcting the data to 3 percent oxygen, and reducing the data to one-hour and daily block averages for all subcategories except units designed to burn liquid fuels located in non-continental states and territories; c. Reducing the data from the daily averages to 10-day rolling averages for all subcategories except units designed to burn liquid fuels located in non-continental states and territories; d. Reducing the data from the one-hour averages to three-hour averages for units designed to burn liquid fuels located in non-continental states and territories; e. Maintaining the 10-day rolling average carbon monoxide concentration at or below the applicable emission limit in Tables 1 or 2 of this subpart for all subcategories except units designed to burn liquid fuels located in non-continental states and territories; and f. Maintaining the 3-hour rolling average carbon monoxide concentration at or below the applicable emission limit in Tables 1 or 2 of this subpart for units designed to burn liquid fuels located in non-continental states and territories.
11. Boiler or process heater operating load.	a. Collecting operating load data or steam generation data every 15 minutes. b. Maintaining the operating load such that it does not exceed 110 percent of the average operating load recorded during the most recent performance test according to § 63.7520(c).

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

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

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.7550(c)(1) through (12); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).

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

You must submit a(n)	The report must contain . . .	You must submit the report . . .
	b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in § 63.7550(d); and d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), or otherwise not operating, the report must contain the information in § 63.7550(e).	

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

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

Citation	Subject	Applies to subpart DDDDD
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes.
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards.	Yes.
§ 63.6(i)	Extension of compliance	Yes. Facilities may request extensions of compliance for the installation of combined heat and power or waste heat recovery as a means of complying with this subpart.
§ 63.6(j)	Presidential exemption	Yes.
§ 63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Conditions for conducting performance tests.	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
§ 63.7(e)(2)–(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§ 63.8(c)(1)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No. See § 63.7500(a)(3).
§ 63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS.	No.
§ 63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.

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

Citation	Subject	Applies to subpart DDDDD
§ 63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program.	Yes.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.
§ 63.8(f)	Use of an alternative monitoring method	Yes.
§ 63.8(g)	Reduction of monitoring data	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns.	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations.	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions.	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results.	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance.	Yes.
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) for malfunction reporting requirements.
§ 63.10(e)	Additional reporting requirements for sources with CMS.	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements.	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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