ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2002–0058; FRL–9919–28–OAR]

RIN 2060–AS09

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

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: On January 31, 2013, the Environmental Protection Agency (EPA) finalized amendments to the national emission standards for the control of hazardous air pollutants (HAP) from new and existing industrial, commercial, and institutional boilers and process heaters at major sources of HAP. Subsequently, the EPA received 10 petitions for reconsideration of the final rule. The EPA is announcing reconsideration of and requesting public comment on three issues raised in the petitions for reconsideration, as detailed in the **SUPPLEMENTARY INFORMATION** section of this notice. The EPA is seeking comment only on these three issues. The EPA will not respond to any comments addressing any other issues or any other 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. Also, we propose to delete rule provisions for an affirmative defense for malfunction in light of a recent court decision on the issue.

DATES: *Comments.* Comments must be received on or before March 9, 2015, or 30 days after date of public hearing if later.

Public Hearing. If anyone contacts us requesting to speak at a public hearing by January 26, 2015, a public hearing will be held on February 5, 2015. If you are interested in attending the public hearing, contact Ms. Pamela Garrett at (919) 541–7966 or by email at *garrett.pamela@epa.gov* to verify that a hearing will be held.

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

• *Federal eRulemaking Portal: http://www.regulations.gov:* Follow the on-line instructions for submitting comments.

• *Email: A-and-R-Docket@epa.gov.* Include docket ID No. EPA–HQ–OAR–2002–0058 in the subject line of the message.

• *Fax:* (202) 566–9744, Attention Docket ID No. EPA–HQ–OAR–2002–0058.

• *Mail:* Environmental Protection Agency, EPA Docket Center (EPA/DC), Mail Code 28221T, Attention Docket ID No. OAR–2002–0058, 1200 Pennsylvania Avenue NW., Washington, DC 20460. The EPA requests a separate copy also be sent to the contact person identified below (see **FOR FURTHER INFORMATION CONTACT**).

• *Hand/Courier Delivery:* EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Avenue NW., Washington, DC 20004, Attention Docket ID No. EPA–HQ–OAR–2002–0058. Such deliveries are only accepted during the Docket's normal hours of operation, 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 on-line at *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 *www.regulations.gov* or email. The *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 *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, the 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.

Public Hearing: If anyone contacts the EPA requesting a public hearing by January 26, 2015, the public hearing will be held on February 5, 2015 at the EPA's campus at 109 T.W. Alexander Drive, Research Triangle Park, North Carolina. The hearing will begin at 10:00 a.m. (Eastern Standard Time) and conclude at 5:00 p.m. (Eastern Standard Time). There will be a lunch break from 12:00 p.m. to 1:00 p.m. Please contact Ms. Pamela Garrett at 919–541–7966 or at *garrett.pamela@epa.gov* to register to speak at the hearing or to inquire as to whether or not a hearing will be held. The last day to pre-register in advance to speak at the hearing will be February 2, 2015. Additionally, requests to speak will be taken the day of the hearing at the hearing registration desk, although preferences on speaking times may not be able to be fulfilled. If you require the service of a translator or special accommodations such as audio description, please let us know at the time of registration. If you require an accommodation, we ask that you pre-register for the hearing, as we may not be able to arrange such accommodations without advance notice. The hearing will provide interested parties the opportunity to present data, views or arguments concerning the proposed action. The EPA will make every effort to accommodate all speakers who arrive and register. Because the hearing is being held at a U.S. government facility, individuals planning to attend the hearing should be prepared to show valid picture identification to the security staff in order to gain access to the meeting room. Please note that the REAL ID Act, passed by Congress in 2005, established new requirements for entering federal facilities. If your driver's license is issued by Alaska, American Samoa, Arizona, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Montana, New York, Oklahoma or the state of Washington, you must present an additional form of identification to enter the federal building. Acceptable alternative forms of identification include: Federal employee badges, passports, enhanced driver's licenses and military identification cards. In addition, you will need to obtain a property pass for any personal belongings you bring with you. Upon leaving the building, you will be required to return this property pass to the security desk. No large signs will be allowed in the building, cameras may only be used outside of the building and demonstrations will not be allowed on federal property for security reasons. The EPA may ask clarifying questions during the oral presentations, but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing. A hearing will not be held unless requested.

Docket: All documents in the docket are listed in the *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 *www.regulations.gov* or in hard copy at the EPA Docket Center (EPA/DC), Room 3334, EPA WJC West Building, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Jim Eddinger, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5426; facsimile number: (919) 541–5450; email address: *eddinger.jim@epa.gov.*

SUPPLEMENTARY INFORMATION:

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

I. General Information

A. What is the source of authority for the reconsideration action?

The statutory authority for this action is provided by sections 112 and 307(d)(7)(B) of the Clean Air Act as amended (42 U.S.C. 7412 and 7607(d)(7)(B)).

B. What entities are potentially affected by the reconsideration action?

Categories and entities potentially regulated 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 final rule.	211	Extractors of crude petroleum and natural gas.
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refineries, and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational services.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. To determine whether your boiler or process heater is regulated by this action, you should examine the applicability criteria in 40 CFR 63.7485. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative, as listed in 40 CFR 63.13 of subpart A (General Provisions).

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

Submitting CBI. Do not submit this information to the EPA through regulations.gov or email. 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. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Send or deliver information identified as CBI to only the following address: Mr. Jim Eddinger, c/o OAQPS Document Control Officer (Mail Drop C404–02), U.S. EPA, Research Triangle Park, NC 27711, Attention Docket ID No. EPA–HQ–OAR–2002–0058.

Docket. The docket number for this notice 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 notice will be posted on the WWW through the

Technology Transfer Network Web site (TTN Web). Following signature, the EPA will post a copy of this notice at *http://www.epa.gov/ttn/atw/boiler/boilerpg.html.* The TTN provides information and technology exchange in various areas of air pollution control.

II. Background

On March 21, 2011, the EPA promulgated national emissions standards for hazardous air pollutants (NESHAP) for the Major Source Boilers and Process Heaters source category. The EPA received a number of petitions for reconsideration on that action, and granted reconsideration on certain issues raised in the petitions. On January 31, 2013, the EPA promulgated amendments to the NESHAP for new and existing industrial, commercial, and institutional boilers and process heaters located at major sources (78 FR 7138). Following promulgation of the January 31, 2013, final rule, the EPA received 10 petitions for reconsideration pursuant to section 307(d)(7)(B) of the Clean Air Act (CAA). The EPA received petitions dated March 28, 2013, from New Hope Power Company and the Sugar Cane Growers Cooperative of Florida. The EPA received a petition dated March 29, 2013, from the Eastman Chemical Company. The EPA received petitions dated April 1, 2013, from Earthjustice, on behalf of Sierra Club, Clean Air Council, Partnership for Policy Integrity, Louisiana Environmental Action Network, and Environmental Integrity Project; American Forest and Paper Association on behalf of American Wood Council, National Association of Manufacturers, Biomass Power Association, Corn Refiners Association, National Oilseed Processors Association, Rubber Manufacturers Association, Southeastern Lumber Manufacturers Association, and U.S. Chamber of Commerce; the Florida Sugar Industry; Council of Industrial Boiler Owners, American Municipal Power, Inc., and American Chemistry Council; American Petroleum Institute; and the Utility Air Regulatory Group which also submitted a supplemental petition on July 3, 2013. Finally, the EPA received a petition dated July 2, 2013, from the Natural Environmental Development Association's Clean Air Project and the Council of Industrial Boiler Owners. The petitions are available for review in the rulemaking docket (see Docket ID No. EPA–HQ–OAR–2002–0058).

On August 5, 2013, the EPA issued letters to the petitioners granting reconsideration on three specific issues raised in the petitions for reconsideration and indicating that the agency would issue a **Federal Register** notice regarding the reconsideration process.[1] This action requests comment on the three issues for which the EPA granted reconsideration and proposes certain revisions to the definitions of startup and shutdown and the work practices that apply during startup and shutdown periods. Additionally, the letters indicated that the EPA intends to make certain clarifying changes and corrections to the final rule, some of which were also raised in the petitions for reconsideration. This action proposes revisions to the regulatory text that would make those clarifications and corrections.

III. Discussion of the Issues Under Reconsideration

The EPA took final action on its proposed amendments to the March 2011 NESHAP on January 31, 2013, (78 FR 7138) to address certain issues raised in the petitions for reconsideration of the 2011 NESHAP.

The January 31, 2013, amendments revised, among other things, the definitions of ''startup'' and ''shutdown'' as well as the work practice requirements for the startup and shutdown periods. The amendments also established a carbon monoxide (CO) threshold level as an appropriate minimum maximum achievable control technology (MACT) floor level that adequately assures sources will be controlling organic HAP emissions to MACT levels. The amendments also replaced the requirement for certain units to install and operate a continuous emission monitoring system (CEMS) measuring particulate matter (PM) emissions with a requirement to install and operate a PM continuous parameter monitoring system (CPMS) which established reporting requirements for deviations and established conditions under which PM CPMS deviations would constitute a presumptive violation of the NESHAP. The EPA received petitions for reconsideration of certain aspects of these requirements, and granted reconsideration of the following three issues on August 5, 2013, to provide an additional opportunity for public comment:

- Definition of startup and shutdown periods and the work practices that apply during such periods;
- Revised CO limits based on a minimum CO level of 130 parts per million (ppm); and
- The use of PM CPMS, including the consequences of exceeding the operating parameter.

The reconsideration petitions stated that the public lacked sufficient opportunity to comment on these provisions. Although these provisions were established after consideration of public comments received on the proposed rule, the EPA is granting reconsideration on these issues in order to allow an additional opportunity for comment. These issues are discussed in more detail in the following sections.

For the startup and shutdown provisions, the EPA is proposing certain revisions to the definitions of startup and shutdown and to the work practice standard that applies during the startup and shutdown periods. The proposed revision to the definition of startup is the addition of an alternate definition of startup. The revision to the work practice standard that applies during the startup period is the addition of an alternate work practice provision regarding the engaging of control devices that applies during startup periods. The EPA is not proposing revisions to the CO limits or the use of PM CPMS, but will consider any input that we receive in this additional public comment opportunity.

Additionally, the EPA is proposing certain clarifying changes and corrections to the final rule, some of which were also raised in the petitions for reconsideration. Specifically, these are: (1) Clarify issues related to the applicability of the major source boiler rule to natural gas-fired electric utility steam generating units (EGUs); (2) clarify the compliance date for coal- or oil-fired EGUs that become subject to the major source boiler rule; (3) correct a conversion error in the MACT floor calculation for existing hybrid suspension grate boilers; (4) clarify certain recordkeeping requirements, including, for example, those related to records for periods of startup and shutdown for boilers and process heaters in the Gas 1 subcategory. The EPA also proposes to clarify and correct certain inadvertent inconsistencies in the final rule regulatory text, such as removal of unnecessary references to statistical equations, inclusion of averaging time for operating load limits in Table 8 to the final rule, and correction of the compliance date for new sources to reflect the effective date of the final rule.

A. Startup and Shutdown Provisions

The EPA received petitions asserting that the public lacked an opportunity to comment on the startup and shutdown provisions amended in the January

[1] The EPA is still reviewing the other issues raised in the petitions for reconsideration and is not taking any action at this time with respect to those issues.

2013, final rule. Specifically, petitioners asserted that the definitions of ''startup'' and ''shutdown'' in the amended final rule failed to address restarts of process heaters and that the provisions for work practice standards did not adequately address fuels considered ''clean'' and operational limitations for certain pollution control devices.

In response to petitions for reconsideration received on the March 2011 NESHAP, the EPA proposed definitions of ''startup'' and ''shutdown'' in December 2011 that were based on load specifications. The EPA received comments on the proposed definitions stating that load specifications within the definitions were inconsistent with either safe or normal (proper) operation of the various types of boilers and process heaters encountered within the source category. As the basis for defining periods of startup and shutdown, a number of commenters suggested that the EPA instead use the achievement of various steady-state conditions. The definitions in the January 2013 final rule addressed these comments by defining startup and shutdown based on the time during which fuel is fired in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity or for any other purpose. As explained in the preamble to the January 2013 final rule, the EPA believes these definitions are appropriate because boilers and process heaters function to provide steam or heat; therefore, boilers and process heaters should be considered to be operating normally at all times steam or heat of the proper pressure, temperature and flow rate is being supplied to a common header system or energy user(s) for use as either process steam or for the cogeneration of electricity.

The EPA also proposed work practices for startup and shutdown periods in the December 2011 notice, which generally required employing good combustion practices. In the January 2013 final rule, the EPA revised the proposed work practice standards after consideration of comments received. Among other things, the revised final work practice standards required sources to combust clean fuels during startup and shutdown periods and required sources to engage air pollution control devices (APCDs) when coal, biomass or heavy oil are fired in the boiler or process heater. (See 78 FR 7198–99.)

We are granting reconsideration on the definitions of startup and shutdown and the work practices that apply during these periods that are in the January 2013 final rule and are also proposing certain revisions to these aspects of the startup and shutdown provisions that are in the January 2013 final rule. We are also proposing an alternate definition of startup and an alternate work practice provision regarding the engaging of pollution control devices.

1. Definitions

We are soliciting comment on the definition of startup and shutdown that were promulgated in the January 2013 final rule, with the clarifying revisions explained below. We are proposing to revise the definitions of startup and shutdown in this reconsideration notice as set forth in 40 CFR 63.7575. Petitioners asserted that the final rule's definitions of startup and shutdown were not sufficiently clear. We are proposing to revise the definitions as explained below.

a. *Definition of Startup Period.* In addition to soliciting public comment on the definition of startup contained in the January 2013 final rule, the EPA is proposing to add an alternate definition to the definition of startup that is in the January 2013 final rule. We are proposing to allow sources to use either definition of startup when complying with the startup requirements. As explained in more detail below, under the alternate definition, startup would end four hours after the unit begins supplying useful thermal energy.

Specifically, the EPA is proposing the alternate definition to clarify that, in terms of the first-ever firing of fuel, startup begins when fuel is fired for the purpose of supplying useful thermal energy (such as steam or heat) for heating, process, cooling, and/or producing electricity and to clarify that startup ends 4 hours after when the boiler or process heater makes useful thermal energy. The proposed clarification regarding the end of startup would apply to first-ever startups as well as startups occurring after shutdown events. With regard to when startup begins after a shutdown event, the alternate definition is the same as the definition in the January 31, 2013, final rule. That is, startup begins with the firing of fuel in a boiler for any purpose after a shutdown event.

In this alternate definition, we are proposing the clarification regarding the first-ever firing of fuel to address implementation issues regarding ''pre-startup'' activities that are done as part of installing a new boiler or process heater. Under the January 2013 definition of ''startup,'' a new boiler or process heater would be considered to have started up, and be subject to the rule, when it first fires fuel ''for any purpose.'' However, a newly installed unit needs to be tested to ensure that it was properly installed and will operate as it was designed and that all associated components were also properly installed and will operate as designed. The EPA did not intend for the startup period to begin when newly installed units first fire fuel for testing or other pre-startup purposes because such firing of fuel does not represent normal operation of the unit.

The EPA is also proposing in the alternate definition to replace the term ''steam and heat'' in the January 2013 definition of startup with the term ''useful thermal energy.'' This proposed revision would apply to first-ever startups as well as startups after shutdown events and is intended to address the issue raised by petitioners that the language in the January 2013 definition regarding the end of the startup period is ambiguous since once fuel is fired some steam or heat is generated but not in useful or controllable quantities. The petitioners comment that it takes time for steam and process fluid to be heated to adequate temperatures and pressures for beneficial use and that steam or heat should not be construed to be supplied until it is of adequate temperature and pressure. The EPA agrees with petitioners that the startup period should not end until such time as fuel is fired resulting in steam or heat that is useful thermal energy because it takes time for steam and process fluids to be heated to adequate temperatures and pressures for beneficial use. We believe the appropriate criteria for ending startup in the definition should be when useful steam is supplied. This proposed change doesn't alter EPA's determination that it is not technically feasible to require stack testing, in particular, to complete the multiple required test runs during periods of startup and shutdown due to physical limitations and the short duration of startup and shutdown periods.

In order to clarify the term ''useful thermal energy,'' we are proposing a definition for ''useful thermal energy'' as follows:

Useful thermal energy means energy (*i.e.,* steam, hot water, or process heat) that meets the minimum operating temperature and/or pressure required by any energy use system that uses energy provided by the affected boiler or process heater.

The EPA received several petitions for reconsideration of the definition of startup in the January 2013 final rule. The petitioners commented that this definition does not account for a wide range of boilers that operationally are still in startup mode even after some steam or heat is supplied to the plant. Specifically, the petitioners commented that what constitutes ''startup'' for all boilers varies widely. For example, petitioners claimed that some boilers begin to supply steam or heat for some purposes onsite before they have achieved necessary temperature or load to engage emission controls.

The petitioners commented that according to the final rule, a boiler supplying even a small amount of steam would no longer be in startup and would be required at that point in time to engage emission controls. However, petitioners noted that according to equipment specifications and established safe boiler operations, a boiler operator should not engage emission controls until specific parameters are met.

The petitioners expressed that, above all, the boiler/process heater operator's primary concern during startup is safety. The startup procedures must ensure that the equipment is brought up to normal operating conditions in a safe manner, and startup ends when the boiler/process heater and its controls are fully functional. The end of startup occurs when safe, stable operating conditions are reached, after emissions controls are properly operating. The startup provisions should not include requirements that could affect safe operating practices.

The EPA agrees with the petitioners that the startup period should not end until such time that all control devices have reached stable conditions. The EPA has very limited information specifically for industrial boilers on the hours needed for controls to reach stable conditions after the start of supplying useful thermal energy. However, the EPA does have information for EGUs on the hours to stable control operation after the start of electricity generation. Using hour-by-hour emissions and operation data for EGUs reported to the agency under the Acid Rain Program, we found that controls used on the best performing 12 percent EGUs reach stable operation within 4 hours after the start of electricity generation. See technical support document titled ''Assessment of Startup Period at Coal-Fired Electric Generating Units—Revised'' in the docket. Since the types of controls used on EGUs are similar to those used on industrial boilers and the start of electricity generation is similar to the start of supplying useful thermal energy, we believe that the controls on the best performing industrial boilers would also reach stable operation within 4 hours after the start of supplying useful thermal energy and have included this timeframe in the proposed alternate definition.[2] This conclusion is supported by the very limited information (13 units) the EPA does have on industrial boilers and by information submitted by the Council of Industrial Boiler Owners obtained from an informal survey of its members on the time needed to reach stable conditions during startup. We welcome comment and additional information on this point during the public comment period.

b. *Definition of Shutdown.* In today's action, the EPA is proposing to revise the definition of shutdown in the January 2013 final rule. The EPA is proposing to clarify that shutdown begins when the boiler or process heater no longer makes useful thermal energy and ends when the boiler or process heater no longer makes useful thermal energy and no fuel is fired in the boiler or process heater. Specifically, the EPA is proposing to revise the regulatory text to replace the term ''steam and heat'' with the term ''useful thermal energy'' to address the same issue as raised by petitioners regarding the language in the definition of ''startup'' described above. The EPA did not intend for the shutdown period to begin until such time as fuel is no longer fired for the purpose of creating useful thermal energy.

The EPA received several petitions for reconsideration of the definition of shutdown in the January 2013 final rule. The petitioners expressed concerns that the definition is problematic for units firing solid fuels on a grate or in a fluidized bed combustor where the residual material in the unit keeps burning after fuel feed to the unit is stopped. In this case, petitioners explained that fuel is still burning (''being fired'') in the unit despite the fact that load reduction is occurring, additional fuel is not being fed, and the shutdown process has clearly begun. For this reason, petitioners recommend that the shutdown definition be revised to state that shutdown begins either when none of the steam and heat from the boiler or process heater is supplied for heating and/or producing electricity or when fuel is no longer being fed to the boiler or process heater and that shutdown ends when there is both no steam or heat being supplied and no fuel being combusted in the boiler or process heater.

The EPA agrees with the petitioners' concerns and intended that the shutdown period would begin when fuel is no longer being fired for the purpose of creating useful thermal energy. The proposed revisions would address the concern raised by the petitioner. The proposed revision is appropriate because as the petitioners commented, for certain types of boilers where the fuel is combusted on a grate or bed, fuel firing may be considered to continue even after fuel feed to the unit is stopped.

2. Work Practice Standards

In today's action, the EPA is proposing to revise the work practice standards in the January 2013 final rule that apply during periods of startup and shutdown. Specifically, the EPA is proposing revisions to the list of ''clean fuel'' in the January 2013 final rule and is proposing an alternate work practice requirement for periods of startup and shutdown. Sources would have the choice of complying with the work practice requirement contained in the January 2013 final rule or the alternate work practice requirement proposed in today's action. Additionally, EPA is proposing a process through which sources can seek an extension of the time period by which the alternate work practice provision requires PM controls to be engaged, based on documented safety considerations. Finally, EPA is proposing certain recordkeeping and monitoring requirements that would apply to sources that choose to comply with the alternate work practice. These proposed provisions are described in more detail below.

a. *Clean Fuel Requirement.* The January 2013 final rule requires sources to startup on ''clean fuel.'' The definition of ''clean fuel'' includes several fuels but does not include coal or biomass or other solid fuels that many sources use during boiler startup. In the December 2011 proposed rule, we solicited 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.''

In a petition for reconsideration, the petitioners claimed that the list of clean fuels, as written, is too narrow. They requested that the EPA expand the list to include all gaseous fuels meeting the ''other gas 1'' classification as well as biodiesel, as distillate oil is sometimes a biodiesel blend. They also requested that fuels that meet the total selected metals (TSM), hydrogen chloride (HCl),

[2] It is important to remember that the hour at which startup ends is the hour at which reporting for the purpose of determining compliance begins. Therefore, sources must collect and report operating limit data following the end of startup. These data are used in calculating whether a source is in compliance with the 30-day average operating limits.

and mercury emission limits using fuel analysis should be added to the list of clean fuels. Dry biomass (less than 20-percent moisture content) should also be added to the list of clean fuels because they claim it will burn cleaner than other solid fuels. Specifically, they claim that it is a clean fuel for startup because it exhibits low HCl, mercury and CO emissions due to its chloride, mercury, and moisture content, and PM emissions would likely be below the dry biomass subcategory PM limit. Therefore, the petition states that it is a reasonable work practice for solid fuel boilers to burn only dry biomass as clean fuel during startup. In addition, the petition recommends that permitting authorities should have the flexibility to approve other clean fuels that EPA may not have considered (*e.g.,* other renewable fuels).

We are proposing two changes to the list of clean fuels for starting up a boiler or process heater. We agree that the list should include all gaseous fuels meeting the ''other gas 1'' classification. Also, we agree that any fuels that meet the applicable TSM, HCl and mercury emission limits using fuel analysis should be added to the list of clean fuels because their mercury, HCl and metals emissions would be in compliance with the applicable emission limits without the use of control devices. Sources would demonstrate compliance either through fuel analysis for the relevant parameters or stack testing. The EPA does not believe it is necessary to revise the regulatory text of the ''clean fuel'' definition to specifically include biodiesel on the list since the definition of ''distillate oil'' in the rule includes biodiesel.

b. *Engaging Pollution Control Devices.* The January 2013 final rule required boilers and process heaters when they start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel or gas 2 (other) gases to engage applicable pollution control devices except for limestone injection in fluidized bed combustion (FBC) boilers, dry scrubbers, fabric filters, selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR), which must start as expeditiously as possible. The EPA received several petitions for reconsideration of this aspect of the work practice standard.

The petitioners expressed concerns that the requirement for engaging applicable control devices does not accommodate potential safety problems relative to electrostatic precipitator (ESP) operation. Comments and recommended manufacturer operating procedures provided to the EPA during the comment period for the December 2011 proposal explained the potential hazards associated with ESP energization when unburned fuel may be present with oxygen levels high enough that the mixture can be in the flammable range. The petitioners referenced these comments and requested that the EPA needs to reconsider this safety issue and revise the requirements to include ESP energization with the other controls that are to be started as expeditiously as possible rather than when solid fuel firing is first started. In addition, they claim that the ESP cannot practically be engaged until a certain flue gas temperature is reached. Specifically, they claim that premature starting of this equipment will lead to short-term stability problems that could result in unsafe actions and longer term degradation of ESP performance due to fouling, increased chances of wire damage, or increased corrosion within the chambers. They also state that vendors providing this equipment incorporate these safety and operational concerns into their standard operating procedures. For example, they claim that some ESPs have oxygen sensors and alarms that shut down the ESP at high flue gas oxygen levels to avoid a fire in the unit. The oxygen level is typically high during startup, so the ESP may not engage due to these safety controls until more stable operating conditions are reached. Therefore, the petitioners request that ESPs be included in the list of air pollution controls that must be started as expeditiously as possible.

Considering the petitioners' comments, the EPA is proposing an alternate work practice requirement for operating air pollution control devices during periods of startup as follows.

Boilers and process heaters owners and operators shall, when firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel or gas 2 (other) gases, vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. Owners and operators must effect PM control within one hour of first firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel or gas 2 (other) gases. Owners and operators must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices.

The EPA believes that the control technology operation related requirements we are proposing are practicable and broadly applicable. Owners and operators of boilers and process heaters have options to minimize any potential for detrimental impacts on hardware and any safety concerns, such as using clean fuels until appropriate flue gas conditions have been reached and then switching to the primary fuel. In addition, we are proposing in the alternate work practice requirement that owners and operators of boilers and process heaters, if they have an applicable emission limit, must develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this subpart and that the SSP must be maintained onsite and available upon request for public inspection. Also in the alternate work practice requirement, we are proposing to allow a source to request a unit-specific case-by-case extension to the 1-hour period for engaging the PM controls. However, the EPA will only consider extensions for units that can provide evidence of a documented manufacturer-identified safety issue and can provide proof that the PM control device is adequately designed and sized to meet the filterable PM emission limit. In its request for the case-by-case determination, the owner/operator must provide, among other materials, documentation that: (1) The unit is using clean fuels to the maximum extent possible to alleviate or prevent the safety issue prior to the combustion of coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel or gas 2 (other) gases in the unit, (2) the source has explicitly followed the manufacturer's procedures to alleviate or prevent the safety issue, (3) details the manufacturer's statement of concern, and (4) provides evidence that the PM control device is adequately designed and sized to meet the PM emission limit.

In order to clarify that the work practice does not supersede any other standard or requirements to which the affected source is subject, the EPA is including in the proposed alternate work practice provision a requirement that requires control devices to operate when necessary to comply with other standards (*e.g.,* new source performance standards, state regulations) applicable to the source that require operation of the control device.

In addition, to ensure compliance with the proposed definition of startup and the work practice standard that applies during startup periods, we are proposing that certain events and parameters be monitored and recorded during the startup periods. These events include the time when firing (*i.e.,* feeding) starts for coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel or gas 2 (other) gases; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged. The parameters to be monitored and recorded include the hourly steam temperature, hourly steam pressure, hourly flue gas temperature, and all hourly average CMS data (*e.g.,* CEMS, PM CPMS, continuous opacity monitoring systems (COMS), ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged.

We request comments on (1) the startup and shutdown provisions (definitions and work practices) in the January 2013 final rule, (2) the proposed alternate definition for ''startup'' and the proposed alternate work practice (item 5.c.(2) of Table 3 of proposed rule) for the startup period, and (3) the recordkeeping requirements being proposed for the startup periods.

B. CO Limits Based on a Minimum CO Level of 130 ppm

In the January 2013 final rule, EPA established a CO emission limit for certain subcategories at a level of 130 ppm, based on an analysis of CO levels and associated organic HAP emissions reductions. See 78 FR 7144. The EPA received a petition for reconsideration of these CO limits in the January 2013 final rule. The petitioner claimed that these limits do not satisfy the statutory requirement that the MACT standard for existing sources is no less stringent than the average emission limitation achieved by the best performing twelve percent of units in the subcategory and that EPA's rationale for adopting these limits is unrelated to this statutory MACT requirement.

The EPA revised these particular CO limits in the January 2013 final rule in part based on comments received during the comment period for the December 2011 proposed rule stating that a CO emission standard no lower than 100 ppm, corrected to 7-percent oxygen, is adequate to assure complete control of organic HAP.

As explained in the preamble to the January 2013 final rule, formaldehyde was selected as the basis of the organic HAP comparison because it was the most prevalent organic HAP in our emission database and a large number (over 300) of paired test runs existed for CO and formaldehyde. The linear relationship between CO and formaldehyde emissions exhibits a high correlation for CO levels above 150 ppm, supporting the selection of CO as a surrogate for organic HAP emissions.

In assessing the correlation between CO and formaldehyde, a trend can be seen that formaldehyde levels are lowest when CO emissions are in the range of 150 to 300 ppm. At levels lower than 150 ppm, the mean levels of formaldehyde appear to increase. Based on this analysis, we promulgated a minimum MACT floor level for CO of 130 ppm, at 3-percent oxygen, (which is equivalent to 100 ppm corrected to 7-percent oxygen) which we believe is protective of human health and the environment.

The EPA does not believe the petitioners have provided sufficient justification that the revised CO limits in the January 2013 final rule do not satisfy the CAA's statutory floor requirements, and the EPA continues to believe that these standards do in fact satisfy the CAA's floor requirements. CAA section 112(d)(3) states that emission standards for existing sources shall not be less stringent, and may be more stringent than ''the average emission limitation achieved by the best performing sources (for which the Administrator has emission information).'' If ''lowest emitting'' is used as the measure for determining ''best performing'' sources, then the 130 ppm standard does satisfy the CAA's floor requirements. When the available formaldehyde emission information is ranked and the best performing 12 percent identified, the mathematical average of the best performing units' corresponding CO emission levels is 240 ppm which is in the range, previously indicated, that formaldehyde emission levels are lowest.

However, in consideration of the fact that the public lacked the opportunity to comment on the CO emission limits established at the level of 130 ppm, corrected to 3-percent oxygen, the EPA has granted reconsideration on the CO emission limits established at the level of 130 ppm, corrected to 3-percent oxygen, to provide an additional opportunity for public comment on those limits. The EPA is not soliciting comment on any other CO limits, or on other issues relating to establishment of CO limits, including the question of whether EPA should establish work practice standards for CO instead of numeric limits.

If, after evaluating all comments and data received on this issue, the EPA determines that amendments to the CO emission limits established at the level of 130 ppm, corrected to 3-percent oxygen, may be appropriate, we will propose such amendments in a future regulatory action.

C. Use of PM CPMS Including Consequences of Exceeding the Operating Parameter

The January 2013 amended final rule requires units combusting solid fossil fuel or heavy liquid with heat input capacities of 250 million British thermal units per hour (MMBtu/hr) or greater to install, maintain, and operate PM CPMS. The provisions regarding PM CPMS in the January 2013 final rule are consistent with regulations for similarly-sized commercial and industrial solid waste incinerator units, Portland cement kilns, and EGUs subject to the Mercury and Air Toxics Standards (MATS) Rule.

The March 21, 2011, final rule required boilers with a heat input rate greater than 250 MMBtu/hr from solid fuel and/or residual oil to install and operate a PM CEMS to demonstrate compliance with the applicable PM emission limit. In petitions for reconsideration to the March 2011 final rule, petitioners objected to this requirement, claiming that the EPA had failed to consider the ability of PM CEMS to meet the required Performance Specification 11 (PS 11) criteria, or to accurately measure PM, at the levels of the proposed standards. In the December 2011 Reconsideration proposal, the EPA acknowledged petitioners' concerns regarding application of PM CEMS technology to various types of boilers, and concluded that for coal- and oil-fired boilers PM CEMS would best be employed as parametric monitors (*i.e.,* as a PM CPMS). Specifically, rather than correlate the PM CEMS to the EPA reference method using PS 11, the EPA proposed that sources establish a site-specific enforceable operating limit in terms of the PM CPMS output during the initial and periodic performance tests, and meet that operating limit on a 30-day rolling average basis. However, commenters objected to the EPA's proposal to impose an enforceable site-specific operating limit based on output during a short-term stack test which would not capture the variability in PM CPMS output that may occur during operations consistent with the PM limit.

In the January 2013 final rule, the EPA finalized the requirement for use of a PM CPMS, but added provisions allowing sources a certain number of exceedances of the operating parameter limit before an exceedance would be presumed to be a violation, and allowing certain low emitting sources to ''scale'' their site-specific operating limit to 75 percent of the emission standard. Specifically, under the January 2013 final rule, boilers opting to use PM CPMS will establish an operating limit as the average parameter value (in terms of raw output from a PM CEMS) obtained during the performance test and, if the boiler did not exceed 75 percent of the emission limit during the performance test, the boiler may linearly scale the average parameter value up to 75 percent of the limit to obtain a new scaled parameter. Compliance with the parameter limit is determined on a 30-boiler-operating-day rolling average basis. For any exceedance of the 30-boiler-operating-day PM CPMS value, the owner or operator must (1) inspect the control device within 48 hours and, if a cause is identified, take corrective action as soon as possible, and (2) conduct a new performance test to verify or reestablish the operating limit within 30 calendar days. Additional exceedances that occur between the original exceedance and the performance test do not trigger another test. Up to four performance tests may be triggered in a 12-month rolling period without additional consequences. However, each additional performance test that is triggered would constitute a separate presumptive violation.

The EPA received a petition for reconsideration on the use of PM CPMS. Specifically, the petitioner stated that while the option has the advantage of avoiding the testing issues associated with PS 11 correlations of PM CEMS, absent that correlation the parameter is nothing more than an indicator that PM may be increasing or decreasing. Therefore, while it is useful as a tool to identify the need for investigation and corrective action, the petitioner does not believe it is an appropriate tool to establish a violation as long as the requirement for corrective action is met.

The petitioner claimed that any affected boiler that tests at its normal operating condition to establish a PM CPMS operating limit could be testing at a level well below the applicable emission limit. For such a boiler, the petitioner does not believe there is any basis to assume that an exceedance (or even multiple exceedances) of a 30-boiler-operating-day rolling average parameter limit indicates that the emission limit was exceeded, or that controls were not operated properly. Rather, the petitioner claims, it simply means that emissions on average probably were above the level of emissions during the last successful performance test. Unless the source has collected data to determine what PM CPMS parameter level is equivalent to a violation of the emission standard, the petitioner states that there is no basis to suggest that any parameter exceedance is a violation. The petitioner also argued that if a source that has invested in a PM CPMS is conducting appropriate investigations and corrective action in response to parameter exceedances, there is no basis to label the source a violator as a result of its fourth successful performance test in a 12-month period.

In its petition for reconsideration, the petitioner also expressed concerns about the scaling procedure that the EPA added to that rule in an attempt to address the fact that ''actual stack emissions of PM could still be well below the limit.'' The petitioner expressed appreciation of the EPA's attempt to address that issue for industrial boilers by also allowing scaling of the as-tested parameter value. However, the petitioner claims that EPA's use of 75 percent of the emission level as the upper point is arbitrary and still puts sources that are operating with significant compliance margin at risk of a violation. For a scaled limit to justify a violation, the petitioner believes that the EPA must establish not only the consistency of the uncorrelated measurements over time, but allow scaling up to 100 percent of the emission limit. Only at that point would there be a reasonable basis to conclude that a performance test might have failed.

In sum, the petitioner claimed that for PM CPMS to be useful as an alternative to stack testing for compliance with the alternate TSM standards or PM CEMS, the EPA must (1) allow scaling up to 100 percent of the emission limit, and (2) remove its definition of a violation in favor of a pure investigation and corrective action approach.

The EPA is not proposing to revise the PM CPMS provisions in the January 31, 2013, final rule. The basis for the inclusion of the definition of a violation is that the site-specific CPMS limit could represent an emissions level higher than the proposed numerical emissions limit since the PM CPMS operating limit corresponds to the highest of the three runs collected during the Method 5 performance test. Second, the PM CPMS operating limit reflects a 30-day average that should represent an actual emissions level lower than the three test run numerical emissions limit since variability is mitigated over time. Consequently, we believe that there should be few if any deviations from the 30-day parametric limit and there is a reasonable basis for presuming that deviations that lead to multiple performance tests to represent poor control device performance and to be a violation of the standard. We continue to believe that there should be few if any deviations from the 30-day parametric limit and that there is a reasonable basis for presuming that deviations that lead to multiple performance tests represent poor control device performance and therefore constitute a presumptive violation of the standard, particularly since that presumption can be rebutted. Therefore, we continue to believe that PM CPMS deviations leading to more than four required performance tests in a 12-month process operating period should be presumed a violation of this standard, subject to the source's ability to rebut that presumption with information about process and control device operations in addition to the Method 5 performance test results. Therefore, the EPA is not proposing to revise that PM CPMS provision in the January 2013 final rule.

Based on an extensive analysis (see S. Johnson's memo ''Establishing an Operating Limit for PM CPMS'', November 2012, docket ID number EPA–HQ–OAR–2011–0817–0840), we also continue to believe a scaling factor of 75 percent of the emission limit as a benchmark is appropriate and are not proposing to revise that provision of the January 2013 final rule. We recognized that non-linear instruments provide increased uncertainty in estimating PM concentrations above the performance test data point and, after considering several options, we determined that the 75-percent scaling cap was appropriate for protecting the emission standard in this regard. This option provided flexibility for low emitting and well-operated sources, and was determined to be a reasonable compromise between flexibility for the regulated source and assurance that the emission standard is met. Seventy-five percent of the emission limit is an already-established threshold in the Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Unit (76 FR 15757) to determine the frequency of subsequent compliance testing. In that rule, owners or operators of sources were able to reduce their performance test frequency when emissions were equivalent with or below 75 percent of the limits. Otherwise, performance testing was to occur at the normal frequency prescribed in the rule. We believe this threshold can be used in conjunction within a PM CPMS scaling factor, as results above 75 percent of the equivalent emissions limit would be ineligible for scaling factor use and could lead to increased performance testing and potentially to a presumptive violation, while results equivalent with or below 75 percent of the emissions limit would be eligible for scaling factor use and provide greater operational flexibility for sources demonstrating compliance at lower emission rates.

For these reasons, the EPA is not proposing to revise the requirements in 40 CFR 63.7440(a)(18) for demonstrating continuous PM emission compliance using a PM CPMS. However, the EPA is soliciting additional comment on these requirements in today's action. The EPA welcomes comments on these provisions, including whether the provisions are necessary or appropriate. If a commenter suggests revisions to the provisions, the commenter should provide detailed information supporting any such revision.

IV. Technical Corrections and Clarifications

We are proposing several technical corrections. These amendments are being proposed to correct inadvertent errors that were promulgated in the final rule and to make the rule language consistent with provisions addressed through this reconsideration. We are soliciting comment only on whether the proposed changes provide the intended accuracy, clarity and consistency. These proposed changes are described in Table 1 of this preamble. We request comment on all of these proposed changes.

TABLE 1—MISCELLANEOUS PROPOSED TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART DDDDD

Section of subpart DDDDD	Description of proposed correction
40 CFR 63.7491(a)	Revise the language in this paragraph to clarify that natural gas-fired EGUs as defined in subpart UUUUU are not subject to the rule if firing at least 90 percent natural gas.
40 CFR 63.7491(j)	Revise this paragraph to include the words "and process heaters" to clarify that it also applies to process heaters.
40 CFR 63.7491(l)	Revise this paragraph to include the words "and process heaters" to clarify that it also applies to process heaters.
40 CFR 63.7491(n)	Insert paragraph (n) which was in amended final rule but inadvertently had the wrong amendatory instruction to be included in the CFR.
40 CFR 63.7495(a)	Revise this paragraph to correctly include the effective date (April 1, 2013) instead of the publication date (January 31, 2013) of the amendments.
40 CFR 63.7495(e)	Revise this paragraph to add the language which was in amended final rule but inadvertently had the wrong amendatory instruction to be included in the CFR.
40 CFR 63.7495(f)	Revise this paragraph to correctly list the date (January 31, 2016) after which existing EGUs that become subject to the rule must be in compliance.
40 CFR 63.7495(h) and (i)	Insert these paragraphs to clarify when existing and new affected units that switch subcategories due to fuel switch or physical change must be in compliance with the provisions of the new subcategory.
40 CFR 63.7500(a)	Revise this paragraph to delete the comma after "paragraphs (b)."
40 CFR 63.7500(a)(1)(ii)	Revise this paragraph by adding the words "on or" to include May 20, 2011.
40 CFR 63.7500(a)(1)(iii)	Revise this paragraph by adding the words "on or" to include December 23, 2011 and to correctly include the effective date (April 1, 2013) instead of the publication date (January 31, 2013) of the amendments.
40 CFR 63.7500(f)	Revise this paragraph to clarify that only items 5 and 6 of Table 3 apply during periods of startup and shutdown.
40 CFR 63.7505(a)	Revise this paragraph by adding the words "emission and operating" to clarify the limits that apply at all times.
40 CFR 63.7505(c)	Revise this paragraph by adding the word "stack" to clarify that the performance testing referred to is performance stack testing.
40 CFR 63.7510(a)(2)(ii)	Revise this paragraph to clarify our intent on fuel type for the analysis requirements for gaseous fuels.
40 CFR 63.7510(a)	Revise this paragraph by adding the word "stack" to clarify that the performance tests referred to are performance stack test.
40 CFR 63.7510(c)	Revise this paragraph to correct the reference to tables 1 and 2, not 12.
40 CFR 63.7510(e)	Revise this paragraph to remove reference to paragraph (j) for the one-time energy assessment because paragraph (j) only repeat the compliance date as indicated in paragraph (e) and to pluralize the word "demonstration."
40 CFR 63.7510(g)	Revise this paragraph to correct the references to 40 CFR 63.7515(d), not 40 CFR 63.7540(a) to clarify the appropriate schedule for conducting periodic tune-ups.
40 CFR 63.7510(i)	Revise this paragraph to correctly list the initial compliance date (January 31, 2016).
40 CFR 63.7510(k)	Add this paragraph to clarify the appropriate schedule for conducting performance tests after a switch in subcategory.
40 CFR 63.7515(d)	Revise this paragraph to clarify that the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, either after April 1, 2013, or the initial startup of the new or reconstructed affected source, whichever is later.
40 CFR 63.7515(h)	Revise this paragraph to clarify that "performance tests" refers to both stack tests and fuel analyses.
40 CFR 63.7521(a)	Revise this paragraph to clarify that gaseous and liquid fuels are not exempt from the sampling requirements in Table 6 of the rule.
40 CFR 63.7521(c)(1)(ii)	Revise this paragraph to remove the requirement to collect monthly samples at 10-day intervals because it is inconsistent with the requirement for monthly fuel analysis in 40 CFR 63.7515(e).
40 CFR 63.7521(f)	Revise this paragraph to clarify that the two methods listed in Table 6 for determining the mercury concentration for other gas 1 fuels are alternatives.
40 CFR 63.7521(g)	Revise this paragraph to remove the requirement to submit for review and approval a site-specific fuel analysis plan for other gas 1 fuels because paragraph (g)(1) requires the plan to be submitted for review and approval only if an alternative analytical method other than those required by Table 6 is intended to be used.
40 CFR 63.7521(h)	Revise this paragraph to remove the reference to sampling procedures listed in Table 6 because there are no sampling procedures listed in Table 6 for gaseous fuel.
40 CFR 63.7522(c)	Revise this paragraph by changing wording from "January 31, 2013" (publication date of the amendments) to "April 1, 2013" (the effective date of the amendments.
40 CFR 63.7522(d)	Revise this paragraph by changing wording from "operating" to "subject to numeric emission limits" to clarify that the numeric emission limits do not apply during startup and shutdown periods.
40 CFR 63.7522(j)(1)	Revise Equation 6 to delete "nanograms per dry standard cubic meter (ng/dscm)" from both EN and Eli since there are not numeric emission limits for dioxin.

TABLE 1—MISCELLANEOUS PROPOSED TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART DDDDD—Continued

Section of subpart DDDDD	Description of proposed correction
40 CFR 63.7525(a)	Revise the paragraph to clarify that the procedures for installing oxygen analyzer system or CO CEMS do not include paragraph (a)(7) because (a)(7) does not require the installation of an oxygen trim system.
40 CFR 63.7525(a), (a)(1), (a)(2), (a)(3), and (a)(5).	Revise these paragraphs to clarify that carbon dioxide may be used as an alternative to using oxygen in correcting the measured CO CEMS data without petitioning for an alternative monitoring procedure.
40 CFR 63.7525(a)(7)	Revise this paragraph to clarify the oxygen set point for a source not required to conduct a CO performance test.
40 CFR 63.7525(b) and (b)(1).	Remove the word "certify" because there is no certification procedure for PM CPMS.
40 CFR 63.7525(b)(1)(iii)	Revise this paragraph to clarify that the 0.5 milligram per actual cubic meter is the detection limit.
40 CFR 63.7525(g)(3)	Revise this paragraph to clarify that the pH monitor is to be calibrated each day and not performance evaluated which is covered in 40 CFR 63.7525(g)(4).
40 CFR 63.7525(m)	Revise this paragraph to clarify that 40 CFR 63.7525(m) is only applicable if the source elects to use an SO_2 CEMS to demonstrate compliance with the HCl emission limit and to clarify that the SO_2 CEMS can be certified according to either part 60 or part 75.
40 CFR 63.7530	Revise equations 7, 8, and 9 to clarify that for "Qi" the highest content of chlorine, mercury, and TSM is used only for initial compliance and the actual fraction is used for continuous compliance demonstration.
40 CFR 63.7530(a)	Revise this paragraph to clarify which fuels are exempt from analysis by cross-referencing 40 CFR 63.7510(a)(2), instead of only 40 CFR 63.7510(a)(2) (i).
40 CFR 63.7530(b)	Revise this paragraph by adding the word "stack" to clarify that the performance testing referred to is performance stack testing.
40 CFR 63.7530(b)(4)(iii) to (viii).	Revise the numbering of these paragraphs to correct sequence.
40 CFR 63.7530(c)(3)	Revise the reference to Equation 11 to be Equation 15, to accommodate the change in numbering of equations.
40 CFR 63.7530(c)(4)	Revise the reference to Equation 11 to be Equation 15, to accommodate the change in numbering of equations.
40 CFR 63.7530(c)(5)	Revise the reference to Equation 11 to be Equation 15, to accommodate the change in numbering of equations.
40 CFR 63.7530(d)	Amend this paragraph to clarify that the requirement to include a signed statement that the tune-up was conducted is applicable to all existing units.
40 CFR 63.7530(e)	Amend this paragraph to clarify that the energy assessment is also considered to have been completed if the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.
40 CFR 63.7530(h)	Revise this paragraph to clarify that both items 5 and 6 of Table 3 apply during periods of startup and shutdown.
40 CFR 63.7530(i)(3)	Revise this paragraph to read "maximum" instead of "minimum" to be consistent with item 10 of Table 4 to subpart DDDDD.
40 CFR 63.7533(e)	Revise this paragraph by changing wording from "operating" to "subject to numeric emission limits" to clarify that the numeric emission limits do not apply during startup and shutdown periods.
40 CFR 63.7535(c)	Amend this paragraph to clarify that data recorded during periods of startup and shutdown may not be used to report emissions or operating levels.
40 CFR 63.7535(d)	Amend this paragraph to clarify that data recorded during periods of startup and shutdown may not be used to report emissions or operating levels and that the report for reporting periods when the monitoring system is out of control is the facility's "semi-annual" report.
40 CFR 63.7540(a)(2)	Revise the reference to 40 CFR 63.7550(c) to 40 CFR 63.7555(d).
40 CFR 63.7540(a)(3) and (a)(3)(iii).	Revise the reference to Equation 12 to Equation 16, to accommodate the change in numbering of equations.
40 CFR 63.7540(a)(5) and (a)(5)(iii).	Revise the reference to Equation 13 to Equation 17, to accommodate the change in numbering of equations.
40 CFR 63.7540(a)(8)(ii)	Revise this paragraph by changing wording from "operating" to "subject to numeric emission limits" to clarify that the numeric emission limits do not apply during startup and shutdown periods.
40 CFR 63.7540(a)(10)	Amend this paragraph to clarify that the tune-up must be conducted while burning the type of fuel that provided the majority of the heat input over the 12 months prior to the tune-up.
40 CFR 63.7540(a)(10)(vi)	Revise paragraph to remove the word "annual" because not all facilities will necessarily be subject to an annual tune-up requirement.
40 CFR 63.7540(a)(17) and (a)(17)(iii).	Revise the reference to Equation 14 to Equation 18, to accommodate the change in numbering of equations.
40 CFR 63.7540(a)(19)(iii)	Revise the reference from paragraph (i) to paragraph (v).
40 CFR 63.7540(d)	Revise the reference to item 5 of Table 3 to items 5 and 6 of Table 3 to accommodate the splitting of the work practice for startup and shutdown into two separate items in Table 3.
40 CFR 63.7545(e)(8)(i)	Revise this paragraph by changing the wording from "complies with" to "completed" to add clarity.
40 CFR 63.7545(h)	Revise this paragraph to clarify the paragraph also applies to process heaters.
40 CFR 63.7550(b)	Revise this paragraph to clarify that units subject only to both the energy assessment and tune-up requirements may submit only an annual, biennial, or 5-year compliance report.
40 CFR 63.7550(b)(1), (b)(2), (b)(3), and (b)(4).	Revise these paragraphs to add the word "semi-annual" to clarify that the compliance report initially discussed in each paragraph is the semi-annual report required for units subject to emission limits.
40 CFR 63.7550(b)(1)	Revise this paragraph to change the reporting period end dates to be consistent with the dates in 40 CFR 63.7550(b)(3).
40 CFR 63.7550 (c)(1)	Revise this paragraph to remove the word "a," to change the wording from "they" to "you" and to add reference to 40 CFR 63.7550(c)(5)(xvii).
40 CFR 63.7550 (c)(2) and (c)(3).	Revise these paragraphs to add reference to 40 CFR 63.7550(c)(5)(xvii).
40 CFR 63.7550 (c)(3)	Revise this paragraph to add reference to 40 CFR 63.7550(c)(5)(viii).
40 CFR 63.7550 (c)(2), (c)(3) and (c)(4).	Revise these paragraphs to change the wording from "a facility is" to "you are" and "they" to "you."
40 CFR 63.7550 (c)(4)	Revise the paragraph to include reference to paragraph (c)(5)(xii).

TABLE 1—MISCELLANEOUS PROPOSED TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART DDDDD—Continued

Section of subpart DDDDD	Description of proposed correction
40 CFR 63.7550(c)(5)(viii) ...	Revise the reference to Equation 12 to Equation 16, the reference to Equation 13 to Equation 17, and the reference to Equation 14 to Equation 18, to accommodate the change in numbering of equations.
40 CFR 63.7550(d)	Revise this paragraph to clarify that deviations from the work practice standards for periods of startup and shutdown must also be included in the compliance report.
40 CFR 63.7550(h)	Revise the paragraph to update electronic reporting requirements.
40 CFR 63.7555(a)(3)	Redesignating paragraph 63.7550(d)(3) as new paragraph 63.7550(a)(3) because limited use units are not subject to emission limits.
40 CFR 63.7555(d)(4)	Change the reference to Equation 12 to Equation 16, to accommodate the change in numbering of equations.
40 CFR 63.7555(d)(5)	Change the reference to Equation 13 to Equation 17, to accommodate the change in numbering of equations.
40 CFR 63.7555(d)(9)	Change the reference to Equation 14 to Equation 18, to accommodate the change in numbering of equations.
40 CFR 63.7555(i) and (j)	Delete paragraphs because paragraphs (i) and (j) are identical to paragraphs (d)(10) and (d)(11) to be consistent with the intent of the amendments to limit these reporting requirements to units subject to emission limits.
40 CFR 63.7575	Revise the definition of "Coal" to clarify that coal derived liquids are considered to be a liquid fuel type.
	Add new definition of "Fossil fuel" to clarify what is meant by "fossil fuel" in the definition of "Electric utility steam generating unit."
	Revise the definition of "Limited-use boiler or process heater" to remove the word "average" to eliminate confusion regarding its use in the definition and maintain consistent terminology within the subpart.
	Revise the definition of "Load fraction" to clarify how load fraction is determined for a boiler or process heater co-firing natural gas.
	Revise the definition of "Oxygen trim system" to include draft controller and to clarify that it is a system that maintains the desired excess air level over the operating load range.
	Revise the definition of "Steam output" to clarify how steam output is determined for multi-function units and units supplying steam to a common header.
	Revise the definition of "Temporary boiler" to clarify that the definition is also applicable to process heaters.
Table 1 to subpart DDDDD ..	Revise the subcategory "Stokers designed to burn coal/solid fossil fuel" to clarify that the subcategory includes "other combustors" consistent with the stokers designed to burn biomass subcategories.
	Add footnote "d" to clarify that carbon dioxide may be used as an alternative to using oxygen in correcting the measured CO CEMS data without petitioning for an alternative monitoring procedure.
Table 2 to subpart DDDDD ..	Revise the subcategory "Stokers designed to burn coal/solid fossil fuel" to clarify that the subcategory includes "other combustors" consistent with the stokers designed to burn biomass subcategories.
	Revise the CO emission limit for hybrid suspension grate units to account for a conversion error in the emission database that inadvertently resulted in a source incorrectly being a best performing unit.
	Revise items 14.b and 16.b to add the reference to footnote "a."
	Add footnote "c" to clarify that carbon dioxide may be used as an alternative to using oxygen in correcting the measured CO CEMS data without petitioning for an alternative monitoring procedure.
Table 3 to subpart DDDDD ..	Revise item 4 to clarify that "operates" does not require the energy management program to be implemented in perpetuity and that an energy management program developed according to ENERGY STAR guidelines would also satisfy the requirement.
	Revise item 4e to read "program" instead of "practices" to be consistent with the definition of "Energy management program" in § 63.7575.
Table 4 to subpart DDDDD ..	Revise certain items in the table to clarify the applicability of the parameter operating limits also apply to process heaters.
	Revise item 4 to clarify that item 4.a. is applicable to dry ESP and item 4.b. is applicable to wet ESP systems.
Table 5 to subpart DDDDD ..	Revise the heading of the third column to clarify that the requirement to use a specified method may not be appropriate in all cases.
	Add the missing footnote "[a] Incorporated by reference, see 40 CFR 63.14"
Table 6 to subpart DDDDD ..	Revise items 1, 2, and 4 to remove reference to the equations cited in 40 CFR 63.7530 for demonstrating only initial compliance.
	Revise items 1.c, 2.c, and 4.c to remove the listed method for liquid samples to be consistent with 40 CFR 63.7521(a).
	Revise item 3 to clarify that the two methods listed are alternatives.
	Revise the title to item 4 to remove "for solid fuels" to clarify that item 4. is applicable to also liquid fuel types.
Table 7 to subpart DDDDD ..	Revise item 1.a.i.(1) to clarify that TSM performance test are also included.
	Revise items 2.a.i. and 2.a.i.(1) to remove "pressure drop" to be consistent with 40 CFR 63.7530(b).
	Revise items 2.b.i.(1)(c) and 3.a.i.(1)(c) to clarify that "load fraction" is as defined in 40 CFR 63.7575.
	Revise item 2.c.i(1)(b) to read "highest" instead of "lowest" to be consistent with item 10 of Table 4 to subpart DDDDD.
	Revise item 4 to read "Carbon monoxide for which compliance is demonstrated by a performance test" to clarify that this operating limit is not applicable for source complying with the CO CEMS based limits.
Table 8 to subpart DDDDD ..	Revise item 3 to change the reference to 40 CFR 63.7540(a)(9) to 40 CFR 63.7540(a)(7).
	Revise item 9.a to change the reference to 40 CFR 63.7525(a)(2) to 40 CFR 63.7525(a)(7).
	Revise item 11.c to read "highest" instead of "minimum" to be consistent with item 10 of Table 4 to subpart DDDDD.
	Revise the operating load compliance provisions (item 10) to be consistent with 40 CFR 63.7525(d).
Table 9 to subpart DDDDD ..	Revise Table 9 to subpart DDDDD to clarify that it is deviations from the work practice standards for periods of startup and shutdown that are to be included.
Table 11 to subpart DDDDD	Revise Table 11 to subpart DDDDD to be consistent with the final amended rule because of incorrect amendatory instructions.
Table 12 to subpart DDDDD	Revise Table 12 to subpart DDDDD to be consistent with the final amended rule because of incorrect amendatory instructions.

V. Affirmative Defense for Violation of Emission Standards During Malfunction

In several prior CAA section 112 and CAA section 129 rules, including this rule, the EPA had included an affirmative defense to civil penalties for violations caused by malfunctions in an effort to create a system that incorporates some flexibility, recognizing that there is a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission standards may be violated under circumstances entirely beyond the control of the source. Although the EPA recognized that its case-by-case enforcement discretion provides sufficient flexibility in these circumstances, it included the affirmative defense to provide a more formalized approach and more regulatory clarity. See *Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal case-by-case enforcement discretion approach is adequate); but see *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977) (requiring a more formalized approach to consideration of ''upsets beyond the control of the permit holder.''). Under the EPA's regulatory affirmative defense provisions, if a source could demonstrate in a judicial or administrative proceeding that it had met the requirements of the affirmative defense in the regulation, civil penalties would not be assessed. Recently, the United States Court of Appeals for the District of Columbia Circuit vacated an affirmative defense in one of the EPA's CAA section 112 regulations. *NRDC* v. *EPA,* 749 F.3d 1055 (D.C. Cir., 2014) (vacating affirmative defense provisions in CAA section 112 rule establishing emission standards for Portland cement kilns). The court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts in such cases lies exclusively with the courts, not the EPA. Specifically, the court found: ''As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are 'appropriate.' '' See *NRDC,* 2014 U.S. App. LEXIS 7281 at *21 (''[U]nder this statute, deciding whether penalties are 'appropriate' . . . is a job for the courts, not EPA.''). In light of *NRDC,* the EPA is proposing to remove the regulatory affirmative defense provision in the current rule.

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

Further, to the extent the EPA files an enforcement action against a source for violation of an emission standard, the source can raise any and all defenses in that enforcement action and the federal district court will determine what, if any, relief is appropriate. The same is true for citizen enforcement actions. Cf. *NRDC* at 1064 (arguments that violation was caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). Similarly, the presiding officer in an administrative proceeding can consider any defense raised and determine whether administrative penalties are appropriate.

VI. Solicitation of Public Comment and Participation

The EPA seeks full public participation in arriving at its final decisions. At this time, the EPA is only proposing alternatives to the final rule's definitions of startup and shutdown, the work practices that apply during those periods, and recordkeeping requirements for startup periods. The EPA is not proposing any other specific revisions to the reconsideration issues. However, the EPA requests public comment on the three issues under reconsideration.

Additionally, the EPA is making certain clarifying changes and corrections to the final rule. We are soliciting comments on whether the proposed changes provide the intended accuracy, clarity and consistency. The EPA is also proposing to amend the final rule by removing the affirmative defense provision. We request comment on all of these proposed changes.

The EPA is seeking comment only on the specific three issues, the clarifying changes and corrections, and the amendments described in this notice. The EPA will not respond to any comments addressing any other issues or any other provisions of the final rule or any other rule.

VII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders*.

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

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under PRA. With this action, the EPA is seeking additional comments on three aspects of the final amended NESHAP for industrial, commercial, and institutional boilers and process heaters located at major sources of HAP with proposing only minor changes to the rule to correct and clarify implementation issues raised by stakeholders. However, the Office of Management and Budget (OMB) has previously approved the information collection requirements contained in the existing regulations under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0551. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. This action seeks comment on three aspects of the final NESHAP for industrial, commercial, and institutional boilers and process heaters located at major sources of HAP as well as proposing minor changes to the rule to correct and clarify implementation issues raised by stakeholders.

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandates as described in UMRA, 2 U.S.C. 1531–1538. The action imposes no enforceable duty on any state, local or tribal governments or the private sector.

This action seeks comment on three aspects of the final NESHAP for industrial, commercial, and institutional boilers and process heaters located at major sources of HAP with proposing minor changes to the rule to correct and clarify implementation issues raised by stakeholders.

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. This action seeks comment on three aspects of the final NESHAP for industrial, commercial, and institutional boilers and process heaters located at major sources of HAP without proposing any changes to the rule. 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 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. This action 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 as applying to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

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

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy.

I. National Technology Transfer and Advancement Act

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

This action does not involve technical standards. Therefore, the EPA did not consider the use of any VCS.

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.

The EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. This action seeks comment on three aspects of the final NESHAP for industrial, commercial, and institutional boilers and process heaters located at major sources of HAP with proposing minor changes to the rule to correct and clarify implementation issues raised by stakeholders.

List of Subjects in 40 CFR Part 63

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

Dated: December 1, 2014.

Gina McCarthy,

Administrator.

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

PART 63— NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

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

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

Subpart DDDDD—[Amended]

■ 2. Section 63.7491 is amended by:
■ a. Revising paragraphs (a), (j) and (l).
■ b. Adding paragraph (n).

The revisions and addition read as follows:

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

* * * * *

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 90 percent natural gas on an annual heat input basis.

* * * * *

(j) Temporary boilers and process heaters as defined in this subpart.

* * * * *

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

* * * * *

(n) Residential boilers as defined in this subpart.

■ 3. Section 63.7495 is amended by:
■ a. Revising paragraphs (a) and (e).
■ b. Adding paragraphs (h) and (i).

The revisions and additions read as follows:

§ 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 April 1, 2013, or upon startup of your boiler or process heater, whichever is later.

* * * * *

(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 and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of § 60.2145(a)(2) and (3) or § 60.2710(a)(2) and (3).

* * * * *

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switch fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after January 31, 2016, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switch fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.

* * * * *

■ 4. Section 63.7500 is amended by revising paragraphs (a)(1) and (f) to read as follows:

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

(a) * * *

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 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, 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 and process heaters that generate either steam, cogenerate steam with electricity, or both. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common heaters would calculate a total steam energy output using equation 21 of § 63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction on or after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction on or after December 23, 2011 and before April 1, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

* * * * *

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with items 5 and 6 of Table 3 to this subpart.

* * * * *

§ 63.7501 [Removed]

■ 5. Section 63.7501 is removed.

■ 6. Section 63.7505 is amended by revising paragraphs (a) and (c) and adding paragraph (e) to read as follows:

§ 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 emission and operating limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

* * * * *

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission 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 (HCl), mercury, or total selected metals (TSM) 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 TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance stack testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

* * * * *

(e) If you have an applicable emission limit, you must develop a site-specific monitoring plan for work practice monitoring during startup periods according to the requirements in Table 3 to this subpart. The site-specific monitoring plan for startup periods must be maintained onsite and available upon request for public inspection.

* * * * *

■ 7. Section 63.7510 is amended by:

■ a. Revising paragraphs (a) introductory text, (a)(2)(ii), (c), (e), (g), and (i) .

■ b. Adding paragraph (k).

The revisions and addition read as follows:

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

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance (stack) testing, your initial compliance requirements include all the following:

* * * * *

(2) * * *

(ii) When natural gas, refinery gas, or other Gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those Gas 1 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 non-Gas 1 gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those non-Gas 1 fuels according to § 63.7521 and Table 6 to this subpart.

* * * * *

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

* * * * *

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstrations, 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, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495.

* * * * *

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7515(d) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7515(d).

* * * * *

(i) For an existing EGU that becomes subject after January 31, 2016, you must demonstrate compliance within 180 days after becoming an affected source.

* * * * *

(k) For affected sources, as defined in § 63.7490, that switch subcategory consistent with § 63.7545(h) after the initial compliance date, you must demonstrate compliance within 60 days of the effective date of the switch, unless you had previously conducted your compliance demonstration for this subcategory within the previous 12 months.

■ 8. Section 63.7515 is amended by revising paragraphs (d) and (h) to read as follows:

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

* * * * *

(d) 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 (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

* * * * *

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra-low sulfur liquid fuel, you do not need to conduct further performance tests (stack tests or fuel analyses) if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

* * * * *

■ 9. Section 63.7521 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (c)(1).
■ c. Revising paragraph (f) introductory text.
■ d. Revising paragraph (g) introductory text.
■ e. Revising paragraph (h).

The revisions read as follows:

§ 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 and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses 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 TSM alternative standard or the HCl 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, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section.

* * * * *

(c) * * *

(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.

* * * * *

(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 (4) of this section, or as an alternative where fuel specification analysis is not practical, you must measure mercury concentration in the exhaust gas when firing only the gaseous fuel to be demonstrated as an other gas 1 fuel in the boiler or process heater according to the procedures in Table 6 to this subpart.

* * * * *

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

* * * * *

(h) You must obtain a single fuel sample for each fuel type for fuel specification of gaseous fuels.

* * * * *

■ 10. Section 63.7522 is amended by revising paragraphs (c), (d), (i), and (j)(1) to read as follows:

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

* * * * *

(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 April 1, 2013 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 April 1, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are subject to numeric emission limits following the compliance date specified in § 63.7495.

* * * * *

(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) * * *

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

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

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu) or parts per million (ppm).
ELi = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu or ppm.
Hi = Heat input from unit i, MMBtu.

* * * * *

■ 11. Section 63.7525 is amended by:
■ a. Revising paragraphs (a) introductory text, (a)(1), (a)(2) introductory text, (a)(3), (a)(5), and (a)(7).
■ b. Revising paragraphs (b) introductory text and (b)(1).
■ c. Revising paragraph (g)(3).
■ d. Revising paragraphs (m) introductory text and (m)(2).

The revisions to read as follows:

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

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen (or carbon dioxide (CO_2)) according to the procedures in paragraphs (a)(1) through (6) of this section.

(1) Install the CO CEMS and oxygen (or CO_2) analyzer by the compliance date specified in § 63.7495. The CO and oxygen (or CO_2) levels shall be monitored at the same location at the outlet of the boiler or process heater.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B; part 75 of this chapter (if an CO_2 analyzer is used); the site-specific monitoring plan developed according to § 63.7505(d); and the requirements in § 63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

* * * * *

(3) Complete a minimum of one cycle of CO and oxygen (or CO_2) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or CO_2) data concurrently. Collect at least four CO and oxygen (or CO_2) 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.

* * * * *

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen (or corrected to an CO_2 percentage determined to be equivalent to 3 percent oxygen) from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling 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 CO concentration from the hourly values.

* * * * *

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart, or if the facility is not required to conduct a performance test, set the oxygen level to the oxygen concentration measured during the most recent tune-up to optimize CO to manufacturer's specification.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, 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. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS 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). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, 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 paragraphs (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 must be expressed as milliamps.

(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 have a documented detection limit of 0.5 milligram per actual cubic meter, or less.

* * * * *

(g) * * *

(3) Calibrate the pH monitoring system in accordance with your monitoring plan at least once each process operating day.

* * * * *

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you elect to use an SO_2 CEMS to demonstrate continuous compliance with the HCl emission limit, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to either part 60 or part 75 of this chapter.

(1) * * *

(2) For on-going quality assurance (QA), the SO_2 CEMS must meet either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

* * * * *

■ 12. Section 63.7530 is amended by:

■ a. Revising paragraphs (a).

■ b. Revising paragraph (b) introductory text.

■ c. Revising paragraphs (b)(1)(iii), (b)(2)(iii), and (b)(3)(iii).

■ d. Revising paragraph (b)(4)(ii)(F).

■ e. Redesignating paragraphs (b)(4)(iii) through (b)(4)(viii) as (b)(4)(iv) through (b)(4)(ix) and adding new paragraph (b)(4)(iii).

■ f. Revising paragraphs (c)(3), (c)(4), and (c)(5).

■ g. Revising paragraph (d).

■ h. Revising paragraph (e).

■ i. Revising paragraph (h).

■ j. Revising paragraph (i)(3).

The revisions and addition read as follows:

§ 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. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance stack 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 TSM 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) * * *

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

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

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 during the initial compliance test. 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month would be used.

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

(2) * * *

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

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

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 during the initial compliance test. 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month would be used.

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

(3) * * *

(iii) You must establish a maximum TSM 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 TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM 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 TSM during the initial compliance test. 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month would be used.

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

(4) * * *

(ii) * * *

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (*e.g.* beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(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 PM and TSM 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 HCl 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.

* * * * *

(c) * * *

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} \left(Ci90 \times Qi \times 1.028\right) \qquad \text{(Eq. 16)}$$

Where:

HCl = HCl 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 15 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 HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} \left(Hgi90 \times Qi \right) \qquad \text{(Eq. 17)}$$

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 15 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 TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n} \left(TSM90i \times Qi \right) \qquad \text{(Eq. 18)}$$

Where:

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

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

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

(d) If you own or operate an existing unit, 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 that the assessment is an accurate depiction of your facility at the time of the assessment or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

* * * * *

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 of this subpart.

(i) * * *

(3) You establish a unit-specific maximum SO_2 operating limit by collecting the maximum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the most recent HCl performance test.

■ 13. Section 63.7533 is amended by revising paragraph (e).

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

* * * * *

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is subject to numeric emission limits, following the compliance date specified in § 63.7495.

* * * * *

■ 14. Section 63.7535 is amended by revising paragraphs (c) and (d).

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

* * * * *

(c) You may not use data recorded during periods of startup and shutdown, 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. In calculating monitoring results, do not use any data collected during periods of startup and shutdown, when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your semi-annual report.

■ 15. Section 63.7540 is amended by:

■ a. Revising paragraph (a)(2) introductory text.

■ b. Revising paragraph (a)(3).

■ c. Revising paragraph (a)(5).

■ d. Revising paragraph (a)(8)(ii).

■ e. Revising paragraph (a)(10) introductory text.

■ f. Revising paragraph (a)(10)(vi) introductory text.

■ g. Revising paragraph (a)(17).

■ h. Revising paragraph (a)(19)(iii).

■ i. Revising paragraph (d).

The revisions read as follows:

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

(a) * * *

(2) As specified in § 63.7550(d), 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:

* * * * *

(3) If you demonstrate compliance with an applicable HCl 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 HCl emission rate using Equation 16 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct 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 HCl 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 HCl emission rate from your boiler or process heater under these new conditions using Equation 16 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

* * * * *

(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 17 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct 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 17 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

* * * * *

(8) * * *

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is subject to numeric emission limits.

* * * * *

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

* * * * *

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

* * * * *

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 18 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct 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 TSM emission rate.

(i) You must determine the TSM 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 TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 18 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

* * * * *

(19) * * *

* * * * *

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (v) of this section.

* * * * *

(d) For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart.

* * * * *

■ 16. Section 63.7545 is amended by revising paragraphs (e)(8)(i) and (h) introductory text.

§ 63.7545 What notifications must I submit and when?

* * * * *

(e) * * *

(8) * * *

(i) ''This facility completed the required initial tune-up according to the procedures in § 63.7540(a)(10)(i) through (vi).''

* * * * *

(h) If you have switched fuels or made a physical change to the boiler or process heater and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

* * * * *

■ 17. Section 63.7550 is amended by revising paragraphs (b), (c), (d) introductory text, (d)(1), and (h) to read as follows:

§ 63.7550 What reports must I submit and when?

* * * * *

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to the energy assessment requirement and 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 Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater 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 semi-annual compliance report must be postmarked or submitted 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 each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

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

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) 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 and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 16 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel 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 17 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 TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of § 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 18 of § 63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater 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 TSM 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.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).

(xi) 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.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) 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.

(xiv) 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.

(xv) 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).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

(xvii) 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.

(xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of § 63.7555(d).

* * * * *

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods if startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

* * * * *

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (defined in § 63.2) required by this subpart, you must submit the results of the performance test, including any associated fuel analyses, following the procedure specified in either paragraph (h)(1)(i) or (h)(1)(ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*).) Performance test data must be submitted in a file format generated through use of the EPA's ERT. Instead of submitting performance test data in a file format generated through the use of the EPA's ERT, you may submit an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site, once the XML schema is available. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT (or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site once the XML schema is available), including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in 63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(2)(i) or (h)(2)(ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT. Instead of submitting performance evaluation data in a file format generated through the use of the EPA's ERT, you may submit an alternate electronic file format consistent with the XML schema listed on the EPA's ERT Web site, once the XML schema is available. If you claim that some of the performance evaluation information being submitted is CBI, you must submit a complete file generated through the use of the EPA's ERT (or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site once the XML schema is available), including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the ERT Web site, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in § 63.13.

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 63.13. You must

begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

■ 18. Section 63.7555 is amended by:

■ a. Adding paragraph (a)(3).

■ b. Removing paragraph (d)(3).

■ c. Redesignating paragraphs (d)(4) through (d)(11) as paragraphs (d)(3) through (d)(10).

■ d. Revising newly designated paragraphs (d)(3), (d)(4), and (d)(8).

■ e. Adding new paragraphs (d)(11) and (12).

■ f. Removing paragraphs (i) and (j).

The revisions and additions read as follows:

§ 63.7555 What records must I keep?

(a) * * *

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

* * * * *

(d) * * *

(3) 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 HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 16 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) 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 17 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.

* * * * *

(8) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530, that were done to demonstrate continuous compliance with the TSM 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 TSM emission rates, using Equation 18 of § 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM 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 TSM fuel input, or TSM emission rates, for each boiler and process heater.

* * * * *

(11) For each startup period, you must maintain records of the time that clean fuel combustion begins; the time when firing (*i.e.,* feeding) start for coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged.

(12) For each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (*e.g.,* CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section.

(i) For a boiler or process heater with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(ii) For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(iii) For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber liquid to fuel ratio and the differential pressure of the liquid during each hour of startup.

* * * * *

■ 19. Section 63.7575 is amended by:

■ a. Revising the definitions for ''Coal,'' ''Limited-use boiler or process heater,'' ''Load fraction,'' ''Oxygen trim system,'' ''Shutdown,'' ''Startup,'' ''Steam output,'' and ''Temporary boiler.''

■ b. Adding in alphabetical order definitions for ''Fossil fuel'' and ''Useful thermal energy.''

■ c. Removing the definition for ''Affirmative defense.''

The revisions read as follows:

§ 63.7575 What definitions apply to this subpart?

* * * * *

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, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases and liquids are excluded from this definition.

* * * * *

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

* * * * *

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable annual capacity factor of no more than 10 percent.

* * * * *

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (*e.g.,* for 50 percent load the load fraction is 0.5). For boilers and process heaters that co-fire natural gas or refinery gas with a solid or liquid fuel, the load fraction is determined by the actual heat input of the solid or liquid fuel divided by heat input of the solid or liquid fuel fired during the performance test (*e.g.,* if the performance test was conducted at 100 percent solid fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas the load fraction is 0.5).

* * * * *

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device over its operating load range. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller or draft controller.

* * * * *

Shutdown means the period in which cessation of operation of a boiler or process heater is initiated for any purpose. Shutdown begins when the boiler or process heater no longer makes useful thermal energy (such as heat or steam) for heating, cooling, or process purposes and/or generates electricity or when no fuel is being fed to the boiler or process heater, whichever is earlier. Shutdown ends when the boiler or process heater no longer makes useful thermal energy (such as steam or heat) for heating, cooling, or process purposes and/or generates electricity, and no fuel is being combusted in the boiler or process heater.

* * * * *

Startup means:

(1) Either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler or process heater is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy (such as steam or heat) for heating, cooling or process purposes, or producing electricity, or the firing of fuel in a boiler or process heater for any purpose after a shutdown event. Startup ends four hours after when the boiler or process heater makes useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

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 the appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input (lb per MWh).

(4) For a boiler that performs multiple functions and produces steam to be used for any combination of (1), (2) and (3) that includes electricity generation (3), the total energy output, in terms of MMBtu of steam output, is the sum of the energy content of steam sent directly to the process and/or used for heating (S_1), the energy content of turbine steam sent to process plus energy in electricity according to (2) above (S_2), and the energy content of electricity generated by a electricity only turbine as (3) above (S_3) and would be calculated using Equation 21 of this section. In the case of boilers supplying steam to one or more common heaters, S_1, S_2, and $MW_{(3)}$ for each boiler would be calculated based on the its (steam energy) contribution (fraction of total stam energy) to the common heater.

$$SO_M = S_1 + S_2 + (MW_{(3)}\ x\ CFn) \qquad \text{(Eq. 21)}$$

Where:

SO_M = Total steam output for multi-function boiler, MMBtu
S_1 = Energy content of steam sent directly to the process and/or used for heating, MMBtu
S_2 = Energy content of turbine steam sent to the process plus energy in electricity according to (2) above, MMBtu
$MW_{(3)}$ = Electricity generated according to (3) above, MWh
CFn = Conversion factor for the appropriate subcategory for converting electricity generated according to (3) above to equivalent steam energy, MMBtu/MWh
CFn for emission limits for boilers in the unit designed to burn solid fuel subcategory = 10.8
CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal = 11.7
CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass = 12.1
CFn for emission limits for boilers in one of the subcategories of units designed to burn liquid fuel = 11.2
CFn for emission limits for boilers in the unit designed to burn gas 2 (other) subcategory = 6.2

* * * * *

Temporary boiler means any gaseous or liquid fuel boiler or process heater 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 or process heater is not a temporary boiler or process heater if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or process heater or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler or process heater that replaces a temporary boiler or process heater 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 within the facility but continues to perform the same or similar function and serve the same electricity, process heat, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

* * * * *

Useful thermal energy means energy (*i.e.,* steam, hot water, or process heat) that meets the minimum operating temperature and/or pressure required by any energy use system that uses energy provided by the affected boiler or process heater.

* * * * *

■ 20. Table 1 to subpart DDDDD of part 63 is revised to read as follows:

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

AS STATED IN § 63.7500, YOU MUST COMPLY WITH THE FOLLOWING APPLICABLE EMISSION LIMITS:

[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 startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel..	a. HCl	2.2E–02 lb per MMBtu of heat input.	2.5E–02 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	8.0E–07 [a] lb per MMBtu of heat input.	8.7E–07 [a] lb per MMBtu of steam output or 1.1E–05 [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.
2. Units designed to burn coal/solid fossil fuel.	a. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	1.1E–03 lb per MMBtu of steam output or 1.4E–02 lb per MWh; or (2.7E–05 lb per MMBtu of steam output or 2.9E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen [d], 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel.	a. CO (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen [d], 30-day rolling average).	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen [d], 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS).	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen [d], 30-day rolling average).	1.2E–01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average.	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS).	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen [d], 30-day rolling average).	5.8E–01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	3.5E–02 lb per MMBtu of steam output or 4.2E–01 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.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	4.2E–01 lb per MMBtu of steam output or 5.1 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	3.5E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (4.2E–03 lb per MMBtu of steam output or 5.6E–02 lb per MWh).	Collect a minimum of 2 dscm per run.

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

AS STATED IN § 63.7500, YOU MUST COMPLY WITH THE FOLLOWING APPLICABLE EMISSION LIMITS:

[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 startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
9. 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 (310 ppm by volume on a dry basis corrected to 3 percent oxygen [d], 30-day rolling average).	2.2E–01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E–04 [a] lb per MMBtu of steam output or 1.2E–03 [a] lb per MWh).	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS).	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen [d], 10-day rolling average).	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	3.1E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (6.6E–03 lb per MMBtu of steam output or 9.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS).	330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen [d], 10-day rolling average).	3.5E–01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.2E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	4.3E–03 lb per MMBtu of steam output or 4.5E–02 lb per MWh; or (5.2E–05 lb per MMBtu of steam output or 5.5E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 [a] lb per MMBtu of heat input).	3.0E–02 lb per MMBtu of steam output or 2.8E–01 lb per MWh; or (5.1E–05 lb per MMBtu of steam output or 4.1E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS).	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen [d], 30-day rolling average).	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	3.3E–02 lb per MMBtu of steam output or 3.7E–01 lb per MWh; or (5.5E–04 lb per MMBtu of steam output or 6.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel.	a. HCl	4.4E–04 lb per MMBtu of heat input.	4.8E–04 lb per MMBtu of steam output or 6.1E–03 lb per MWh.	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E–07 [a] lb per MMBtu of heat input.	5.3E–07 [a] lb per MMBtu of steam output or 6.7E–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

AS STATED IN § 63.7500, YOU MUST COMPLY WITH THE FOLLOWING APPLICABLE EMISSION LIMITS:

[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 startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–02 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	1.5E–02 lb per MMBtu of steam output or 1.8E–01 lb per MWh; or (8.2E–05 lb per MMBtu of steam output or 1.1E–03 lb per MWh).	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	1.2E–03 [a] lb per MMBtu of steam output or 1.6E–02 [a] lb per MWh; or (3.2E–05 lb per MMBtu of steam output or 4.0E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	2.5E–02 lb per MMBtu of steam output or 3.2E–01 lb per MWh; or (9.4E–04 lb per MMBtu of steam output or 1.2E–02 lb per MWh).	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.16 lb per MMBtu of steam output or 1.0 lb per MWh.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	2.9E–03 lb per MMBtu of steam output or 1.8E–02 lb per MWh.	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 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 PM (or TSM).	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 7.0E–02 lb per MWh; or (3.5E–04 lb per MMBtu of steam output or 2.2E–03 lb per MWh).	Collect a minimum of 3 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 below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before January 31, 2013, you may comply with the emission limits in Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

[d] An owner or operator may request that compliance with the carbon monoxide emission limit be determined using carbon dioxide measurements corrected to an equivalent of 3 percent oxygen. The relationship between oxygen and carbon dioxide levels for the affected facility shall be established during the initial compliance test.

■ 21. Table 2 to subpart DDDDD of part 63 is revised to read as follows:

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS AS STATED IN § 63.7500, YOU MUST COMPLY WITH THE FOLLOWING APPLICABLE EMISSION LIMITS:

[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 startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E–02 lb per MMBtu of heat input.	2.5E–02 lb per MMBtu of steam output or 0.27 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	5.7E–06 lb per MMBtu of heat input.	6.4E–06 lb per MMBtu of steam output or 7.3E–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.
2. Units design to burn coal/solid fossil fuel.	a. Filterable PM (or TSM).	4.0E–02 lb per MMBtu of heat input; or (5.3E–05 lb per MMBtu of heat input).	4.2E–02 lb per MMBtu of steam output or 4.9E–01 lb per MWh; or (5.6E–05 lb per MMBtu of steam output or 6.5E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. CO (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel.	a. CO (or CEMS).	160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average).	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average.	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average).	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS).	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average).	1.3E–01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average.	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS).	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average).	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.7E–02 lb per MMBtu of heat input; or (2.4E–04 lb per MMBtu of heat input).	4.3E–02 lb per MMBtu of steam output or 5.2E–01 lb per MWh; or (2.8E–04 lb per MMBtu of steam output or 3.4E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	4.2E–01 lb per MMBtu of steam output or 5.1 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.2E–01 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	3.7E–01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E–03 lb per MMBtu of steam output or 5.6E–02 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

AS STATED IN § 63.7500, YOU MUST COMPLY WITH THE FOLLOWING APPLICABLE EMISSION LIMITS:

[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 startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
9. Fluidized bed units designed to burn biomass/bio-based solid.	a. CO (or CEMS).	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average).	4.6E–01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–01 lb per MMBtu of heat input; or (1.2E–03 lb per MMBtu of heat input).	1.4E–01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E–03 lb per MMBtu of steam output or 1.7E–02 lb per MWh).	Collect a minimum of 1 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solid.	a. CO (or CEMS).	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average).	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	5.1E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	5.2E–02 lb per MMBtu of steam output or 7.1E–01 lb per MWh; or (6.6E–03 lb per MMBtu of steam output or 9.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid.	a. CO (or CEMS).	770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average).	8.4E–01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.8E–01 lb per MMBtu of heat input; or (2.0E–03 lb per MMBtu of heat input).	3.9E–01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E–03 lb per MMBtu of steam output or 2.8E–02 lb per MWh).	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid.	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen.	2.4 lb per MMBtu of steam output or 12 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (5.8E–03 lb per MMBtu of heat input).	5.5E–02 lb per MMBtu of steam output or 2.8E–01 lb per MWh; or (1.6E–02 lb per MMBtu of steam output or 8.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid.	a. CO (or CEMS).	3,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average).	3.5 lb per MMBtu of steam output or 39 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	4.4E–01 lb per MMBtu of heat input; or (4.5E–04 lb per MMBtu of heat input).	5.5E–01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E–04 lb per MMBtu of steam output or 6.3E–03 lb per MWh).	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel.	a. HCl	1.1E–03 lb per MMBtu of heat input.	1.4E–03 lb per MMBtu of steam output or 1.6E–02 lb per MWh.	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E–06[a] lb per MMBtu of heat input.	2.5E–06[a] lb per MMBtu of steam output or 2.8E–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 2 dscm.

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

AS STATED IN § 63.7500, YOU MUST COMPLY WITH THE FOLLOWING APPLICABLE EMISSION LIMITS:

[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 startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	6.2E–02 lb per MMBtu of heat input; or (2.0E–04 lb per MMBtu of heat input).	7.5E–02 lb per MMBtu of steam output or 8.6E–01 lb per MWh; or (2.5E–04 lb per MMBtu of steam output or 2.8E–03 lb per MWh).	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	7.9E–03 [a] lb per MMBtu of heat input; or (6.2E–05 lb per MMBtu of heat input).	9.6E–03 [a] lb per MMBtu of steam output or 1.1E–01 [a] lb per MWh; or (7.5E–05 lb per MMBtu of steam output or 8.6E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.7E–01 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	3.3E–01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E–03 lb per MMBtu of steam output or 1.2E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.16 lb per MMBtu of steam output or 1.0 lb per MWh.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	2.9E–03 lb per MMBtu of steam output or 1.8E–02 lb per MWh.	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 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 2 dscm.
	d. Filterable PM (or TSM).	6.7E–03 lb per MMBtu of heat input or (2.1E–04 lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 7.0E–02 lb per MWh; or (3.5E–04 lb per MMBtu of steam output or 2.2E–03 lb per MWh).	Collect a minimum of 3 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 below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] An owner or operator may request that compliance with the carbon monoxide emission limit be determined using carbon dioxide measurements corrected to an equivalent of 3 percent oxygen. The relationship between oxygen and carbon dioxide levels for the affected facility shall be established during the initial compliance test.

■ 22. Table 3 to subpart DDDDD of part 63 is amended by revising the entry for ''4,'' ''5,'' and ''6'' to read as follows:

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

[As stated in § 63.7500, you must comply with the following applicable work practice standards:]

If your unit is . . .	You must meet the following . . .
4. An existing boiler or process heater located at a major source facility, not including limited use units.	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in § 63.7495 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575: a. A visual inspection of the boiler or process heater system. b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints. c. An inventory of major energy use 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 program and provide recommendations for improvements consistent with the definition of energy management program, if identified. f. A list of cost-effective energy conservation measures that are within the facility's control. 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 boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup.	a. You must operate all CMS during startup. b. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis. c. You have the option of complying using either of the following work practice standards. (1) If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose, OR (2) If you choose to comply using definition (2) of "startup" in § 63.7575, once you start firing (i.e., feeding) coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must effect PM control within one hour of first firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases[a]. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown.	You must operate all CMS during shutdown. While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas. You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.

[a] The source may request a variance with the PM controls requirement. The source must provide evidence that (1) meeting the "fuel firing + 1 hour" requirement violates manufacturer's recommended operation and/or safety requirements, and (2) the PM control device is appropriately designed and sized to meet the filterable PM emission limit.

■ 23. Table 4 to subpart DDDDD of part 63 is revised to read as follows:

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

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

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control on a boiler or process heater 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 or process heater not using a HCl 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 a boiler or process heater 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 alert is not activated more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on a boiler or process heater 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).
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., dry ESP). 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.
5. Dry scrubber or carbon injection control on a boiler or process heater 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 a boiler or process heater 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 highest hourly average operating load recorded during the most recent performance test.
9. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2 analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a).
10. SO_2CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2CEMS, maintain the 30-day rolling average SO_2emission rate at or below the highest hourly average SO_2concentration measured during the most recent HCl performance test, as specified in Table 8.

■ 24. Table 5 to subpart DDDDD of part 63 is amended by revising the heading to the third column and adding the footnote ''a'' to read as follows:

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

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

To conduct a performance test for the following pollutant . . .	You must . . .	Using, as appropriate . . .
* * *	* *	*

[a] Incorporated by reference, see § 63.14.

■ 25. Table 6 to subpart DDDDD of part 63 is revised to read as follows:

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS

[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:]

To conduct a fuel nalysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], 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 ASTM D4177 [a] (for liquid), or ASTM D4057 [a] (for liquid), 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), ASTM D2013/D2013M [a] (for coal), ASTM D5198 [a] (for biomass), or EPA 3050 [a] (for solid fuel), or EPA 821–R–01–013 [a] (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 [a] for liquids and other solids, or ASTM D240 [a] or equivalent.
	e. Determine moisture content of the fuel type.	ASTM D3173 [a], ASTM E871 [a], or ASTM D5864 [a], or ASTM D240, or ASTM D95 [a] (for liquid fuels), or ASTM D4006 [a] (for liquid fuels), or ASTM D4177 [a] (for liquid fuels) or ASTM D4057 [a] (for liquid fuels), 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.
2. HCl	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a] (for coal) or ASTM D6323 [a] (for coal or biomass), ASTM D4177 [a] (for liquid fuels) or ASTM D4057 [a] (for liquid fuels), 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), ASTM D2013/D2013M [a] (for coal), or ASTM D5198 [a] (for biomass), or EPA 3050 [a] 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 [a] or equivalent.
	e. Determine moisture content of the fuel type.	ASTM D3173 [a] or ASTM E871 [a], or D5864 [a], or ASTM D240 [a], or ASTM D95 [a] (for liquid fuels), or ASTM D4006 [a] (for liquid fuels), or ASTM D4177 [a] (for liquid fuels) or ASTM D4057 [a] (for liquid fuels) or equivalent.
	f. Measure chlorine concentration in fuel sample.	EPA SW–846–9250 [a], ASTM D6721 [a], ASTM D4208 [a] (for coal), or EPA SW–846–5050 [a] or ASTM E776 [a] (for solid fuel), or EPA SW–846–9056 [a] or SW–846–9076 [a] (for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content.	Equation 7 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, or.	Method 30B (M30B) at 40 CFR part 60, appendix A–8 of this chapter or ASTM D5954 [a], ASTM D6350 [a], ISO 6978–1:2003(E) [a], or ISO 6978–2:2003(E) [a], or EPA–1631 [a] or equivalent.
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater.	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A–8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784 [a] or equivalent.
4. TSM	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a] (for coal) or ASTM D6323 [a] (for coal or biomass), or ASTM D4177 [a], (for liquid fuels)or ASTM D4057 [a] (for liquid fuels), 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), ASTM D2013/D2013M [a] (for coal), ASTM D5198 [a] or TAPPI T266 [a] (for biomass), or EPA 3050 [a] or equivalent.
	d. Determine heat content of the fuel type.	ASTM D5865 [a] (for coal) or ASTM E711 [a] (for biomass), or ASTM D5864 [a] for liquids and other solids, or ASTM D240 [a] or equivalent.
	e. Determine moisture content of the fuel type.	ASTM D3173 [a] or ASTM E871 [a], or D5864, or ASTM D240 [a], or ASTM D95 [a] (for liquid fuels), or ASTM D4006 [a] (for liquid fuels), or ASTM D4177 [a] (for liquid fuels) or ASTM D4057 [a] (for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample.	ASTM D3683 [a], or ASTM D4606 [a], or ASTM D6357 [a] or EPA 200.8 [a] or EPA SW–846–6020 [a], or EPA SW–846–6020A [a], or EPA SW–846–6010C [a], EPA 7060 [a] or EPA 7060A [a] (for arsenic only), or EPA SW–846–7740 [a] (for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content.	Equation 9 in § 63.7530.

[a] Incorporated by reference, see § 63.14.

■ 26. Table 7 to subpart DDDDD of part 63 is revised to read as follows:

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS

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

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM, TSM, 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 PM, TSM, 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 PM 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. HCl	a. Wet scrubber operating parameters.	i. Establish site-specific minimum effluent pH and flow rate operating limits according to § 63.7530(b).	(1) Data from the pH and liquid flow-rate monitors and the HCl performance test.	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests. (b) Determine the 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 HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.	(1) Data from the sorbent injection rate monitors and HCl or 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, as defined in § 63.7575, to determine the required injection rate.
	c. Alternative Maximum SO_2 emission rate.	i. Establish a site-specific maximum SO_2 emission rate operating limit according to § 63.7530(b).	(1) Data from SO_2 CEMS and the HCl performance test.	(a) You must collect the SO_2 emissions data according to § 63.7525(m) during the most recent HCl performance tests.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

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

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(b) The maximum SO_2 emission rate is equal to the highest hourly average SO_2 emission rate measured during the most recent HCl performance tests.
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. (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, as defined in § 63.7575, to determine the required injection rate.
4. Carbon monoxide for which compliance is demonstrated by a performance test.	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7530(b).	(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.

■ 27. Table 8 to subpart DDDDD of part 63 is amended by revising the entry for ''3,'' ''9,'' ''10,'' and ''11'' to read as follows:

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

[As stated in § 63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:]

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
*	* * * *
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)(7) are met.
*	* * * *
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(7). 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 CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Reducing the data to 30-day rolling averages; and b. Maintaining the 30-day rolling average operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to § 63.7520(c).
11. SO_2emissions using SO_2CEMS	a. Collecting the SO_2CEMS output data according to § 63.7525; b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average SO_2CEMS emission rate to a level at or below the highest hourly SO_2rate measured during the most recent HCl performance test according to § 63.7530.

■ 28. Table 9 to subpart DDDDD of part 63 is revised to read as follows:

TABLE 9 TO SUBPART DDDDD OF PART 63—REPORTING REQUIREMENTS

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

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 (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).
	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 for periods of startup and shutdown 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 for periods of startup and shutdown, 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).	

* * * * *

■ 29. Table 11 to subpart DDDDD of part 63 is revised to read as follows:

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis.	a. Mercury	8.0E–07 [a] lb per MMBtu of heat input.	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.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis.	a. Mercury	2.0E–06 lb per MMBtu of heat input.	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.
4. Units design to burn coal/solid fossil fuel.	a. Filterable PM (or TSM)	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
5. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 30-day rolling average).	1 hr minimum sampling time.
6. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 10-day rolling average).	1 hr minimum sampling time.
7. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 30-day rolling average).	1 hr minimum sampling time
8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 30-day rolling average).	1 hr minimum sampling time.
9. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
11. 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 (310 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
12. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	8.0E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
14. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel.	a. HCl	4.4E–04 lb per MMBtu of heat input.	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E–07 [a] lb per MMBtu of heat input.	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.
17. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E–02 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
19. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	Collect a minimum of 4 dscm per run.
20. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	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 PM (or TSM)	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	Collect a minimum of 3 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 below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] An owner or operator may request that compliance with the carbon monoxide emission limit be determined using carbon dioxide measurements corrected to an equivalent of 3 percent oxygen. The relationship between oxygen and carbon dioxide levels for the affected facility shall be established during the initial compliance test.

■ 29. Table 12 to subpart DDDDD of part 63 is revised to read as follows:

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	3.5E–06 [a] lb per MMBtu of heat input	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. Units design to burn coal/solid fossil fuel.	a. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 30-day rolling average)	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 10-day rolling average)	1 hr minimum sampling time.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS) ..	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 30-day rolling average)	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS) ..	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 30-day rolling average)	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS) ..	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS) ..	260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS) ..	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS) ..	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.2E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
13. 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 (900 ppm by volume on a dry basis corrected to 3 percent oxygen [c], 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E–04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Mercury	4.8E–07 [a] lb per MMBtu of heat input ..	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.
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–02 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input	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 PM (or TSM).	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input)	Collect a minimum of 3 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 below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] An owner or operator may request that compliance with the carbon monoxide emission limit be determined using carbon dioxide measurements corrected to an equivalent of 3 percent oxygen. The relationship between oxygen and carbon dioxide levels for the affected facility shall be established during the initial compliance test.

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