ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2002–0058; FRL–6312–02–OAR]

RIN 2060–AU20

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes amendments to the national emission standards for hazardous air pollutants (NESHAP) at major sources from new and existing industrial, commercial, and institutional (ICI) boilers and process heaters. Certain aspects of these standards were challenged and subsequently remanded to the Agency by the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). This action finalizes amendments to several numeric emission limits for new and existing boilers and process heaters consistent with the court's opinion and sets compliance dates for these new emission limits. This action also provides further explanation of one aspect of the Agency's use of carbon monoxide (CO) as a surrogate for organic hazardous air pollutants (HAP) and its use of a CO threshold to represent the application of the maximum achievable control technology (MACT) for organic HAP. We are also finalizing several technical clarifications and corrections.

DATES: This final rule is effective on December 5, 2022. The incorporation by reference (IBR) of certain material listed in the rule is approved by the Director of the Federal Register as of October 6, 2022. The incorporation by reference of this material was previously approved by the Director of the Federal Register as of May 20, 2011.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact Lisa Thompson, Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–9775; and email address: *thompson.lisa@epa.gov* or Nick Hutson, Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–2968; and email address: *hutson.nick@epa.gov.*

SUPPLEMENTARY INFORMATION:

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2002–0058. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov/.* Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room are closed to the public, with limited exceptions, to reduce the risk of transmitting COVID–19. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform.

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I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

a. Need for Regulatory Action

The NESHAP for Industrial, Commercial, and Institutional Boilers (ICI) and Process Heaters was promulgated on March 21, 2011 and amended on January 31, 2013 and again on November 20, 2015. Environmental groups and industry submitted petitions seeking judicial review of the 2013 NESHAP. On July 29, 2016, the D.C. Circuit remanded for further explanation the use of CO as a surrogate for organic HAP due to the EPA's failure to address a public comment received and vacated certain emission standards where it held that the EPA had improperly excluded certain units in establishing the emission standards. *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 631. On December 23, 2016, the D.C. Circuit amended its July 29, 2016 decision to remand those emission standards instead of vacating them. 844 F.3d 268. In March 2018, the court, in a separate challenge to the 2015 amended NESHAP, remanded for further explanation the EPA's decision to set a limit of 130 parts per million (ppm) CO as a minimum standard for certain subcategories of boilers and process heaters. *Sierra Club* v. *EPA,* 884 F.3d 1185.

In response to these remands, the EPA is finalizing revisions to several emission standards consistent with the court's opinion and providing further explanation of the two issues remanded for that purpose.

b. Legal Authority

The statutory authority for this final action is section 112 of the Clean Air Act (CAA). Section 112(d)(2) of the CAA directs the EPA to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT based standards. This NESHAP applies to all ICI boilers and process heaters located at major sources of HAP emissions.[1]

2. Summary of the Major Provisions of the Regulatory Action in Question

The EPA is finalizing revisions to 34 different emission limits which it had previously promulgated in 2011 and amended in 2013. Of these 34 emission limits, 28 of the limits are more stringent and six of the limits are less stringent than the previously promulgated emission limits. The EPA is also finalizing a deadline of 3 years after the effective date of the final rule for sources to demonstrate compliance with these revised emission limits. A list of each combination of subcategory and pollutant with revised limits is shown in Table 1.

TABLE 1—SUMMARY OF SUBCATEGORIES WITH REVISED EMISSION LIMITS

Subcategory	Pollutant
New-Solid	HCl.
New-Dry Biomass Stoker	TSM.*
New-Biomass Fluidized Bed	CO, PM, TSM.
New-Biomass Suspension Burner	CO, TSM.*
New-Biomass Hybrid Suspension Grate.	CO.
New-Biomass Dutch Oven/Pile Burner.	PM.
New-Biomass Fuel Cell	PM.
New-Wet Biomass Stoker	CO, PM.
New-Liquid	HCl.
New-Heavy Liquid	PM, TSM.
New-Process Gas	PM.*
Existing-Solid	HCl, Hg.
Existing-Coal	PM.
Existing-Coal Stoker	CO.
Existing-Dry Biomass Stoker	TSM.*
Existing-Wet Biomass Stoker	CO, PM, TSM.
Existing-Biomass Fluidized Bed	CO, PM, TSM.
Existing-Biomass Suspension Burners.	PM, TSM.*
Existing-Biomass Dutch Oven/Pile Burner.	PM.
Existing-Liquid	Hg.
Existing-Heavy Liquid	PM.
Existing-Non-continental Liquid	PM.
Existing-Process Gas	PM.*

* Indicates a less stringent limit compared to the previously promulgated emission limits.

3. Costs and Benefits

We have estimated certain costs and benefits of the final rule, and these are found in Table 2. All of these estimates are in 2016 dollars (2016$). The monetized benefits estimate reflects an annual average of 446 tons of fine particulate matter ($PM_{2.5}$) emission reductions per year and 1,141 tons of sulfur dioxide (SO_2) emission reductions per year, both pollutants not directly regulated by this final rule. The unmonetized benefits include reduced exposure to directly regulated HAP, including mercury (Hg), hydrochloric acid (HCl), non-Hg metals (*e.g.,* antimony, cadmium), formaldehyde, benzene, and polycyclic organic matter; reduced climate effects due to reduced black carbon emissions; reduced ecosystem effects; and reduced visibility impairments. These estimates also include climate disbenefits resulting from an increase in carbon dioxide (CO_2) emissions, a secondary impact from electricity use by additional control devices in response to the final amendments.

Table 2 presents estimates of the present values (PV) and equivalent annualized values (EAV), calculated using discount rates of 3 and 7 percent as directed by OMB's Circular A–4, of the health benefits, climate disbenefits, compliance costs, and net benefits of the final rule, in 2016 dollars, discounted to 2020. The estimated net benefits are the estimated benefits minus the estimated disbenefits and the estimated costs of the final rule.

TABLE 2—ESTIMATED HEALTH BENEFITS, CLIMATE DISBENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE FINAL RULE, 2022 THROUGH 2029

[Millions 2016$, discounted to 2020][a]

	3% Discount rate	7% Discount rate
Present Value:		
Health Benefits[b]	$500 and $505	$350 and $353.
Climate Disbenefits[b]	$7	$7.
Compliance Costs[c]	$315	$265.
Net Benefits[d]	$178 and $182 + B	$80 and $83 + B.
Equivalent Annualized Value:		
Health Benefits	$71 and $72	$58 and $59.
Climate Disbenefits	$1	$1.
Compliance Costs	$45	$44.
Net Benefits	$25 and $26 + C	$13 and $14 + C.

[a] Numbers may not sum due to independent rounding.

[b] The health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. The health benefits are a result of the $PM_{2.5}$ and SO_2 emission reductions estimated for this final rule, and are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed. Data, resource, and methodological limitations prevented the EPA from monetizing the human health benefits from reduced exposure to mercury, HCl, and other HAP whose emissions are directly regulated by this final rule. The EPA provides a qualitative discussion of mercury, HCl, and other HAP benefits in the RIA. In addition, the potential benefits from reduced ecosystem effects and reduced visibility impairment from the reduction in emissions of non-HAP pollutants such as $PM_{2.5}$ and SO_2 are also not monetized here. Climate disbenefits are based on changes (increases) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC–CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the climate disbenefits associated with the average SC–CO_2 at a 3 percent discount rate, but the Agency does not have a single central SC–CO_2 point estimate. We emphasize the importance and value of considering the disbenefits calculated using all four SC–CO_2 estimates; the additional disbenefit estimates are presented in section V of this preamble. As discussed in Chapter 4 of the Regulatory Impact Analysis (RIA) for this final rule, a consideration of climate disbenefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

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[1] See 75 FR 32016 and § 63.7575 "What definitions apply to this subpart" of 40 CFR part 63, subpart DDDDD, for definitions of ICI boilers and process heaters.

[c] To estimate these annualized costs, the EPA uses a conventional and widely accepted approach, the equivalent uniform annual cost (EUAC) approach, that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. Annual costs were calculated using a 5.5% nominal interest rate consistent with the rate used for the cost analysis done for the proposed rule.

[d] The letter "B" captures the portion of the present value of net benefits due to the unmonetized benefits from the emission reductions of directly regulated HAP and all other emission changes resulting from this final rule. The letter "C" captures the portion of the equivalent annualized value of net benefits due to the unmonetized benefits from the emission reductions of directly regulated HAP and all other emission changes resulting from this final rule. The benefits from emission reductions of directly regulated HAP under this final rule are not monetized due to lack of appropriate valuation estimates. More information on the unmonetized benefits from HAP and non-HAP emission reductions can be found in Chapter 4 of the RIA.

As shown in Table 2, the PV of the health benefits of this final rule, discounted at a 3-percent discount rate, is estimated to be about $500 million and $505 million, with an EAV of about $71 million and $72 million. At a 7-percent discount rate, the PV of the health benefits is estimated to be $350 million and $353 million, with an EAV of about $58 million and $59 million. The two health benefits estimates for each discount rate reflect alternative $PM_{2.5}$ mortality risk estimates. The PV of the climate disbenefits of this final rule, discounted at a 3-percent rate, is estimated to be about $7 million, with an EAV of about $1 million. The PV of the compliance costs, discounted at a 3-percent rate, is estimated to be about $315 million, with an EAV of about $45 million. At a 7-percent discount rate, the PV of the compliance costs is estimated to be about $265 million, with an EAV of about $44 million.

More information on these impacts can be found in section V of this preamble and in the Regulatory Impact Analysis (RIA) for this final rule.

B. Does this action apply to me?

Table 3 lists the NESHAP and associated regulated industrial source categories that are the subject of this action. Table 3 is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that this action affects. The final standards will be directly applicable to the affected sources. As defined in the *Initial List of Categories of Sources Under Section 112(c)(1) of the Clean Air Act Amendments of 1990* (see 57 FR 31576, July 16, 1992) and *Documentation for Developing the Initial Source Category List, Final Report* (see EPA–450/3–91–030, July 1992), the Industrial/Commercial Boiler source category includes boilers used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity. The Institutional/Commercial Boilers source category includes, but is not limited to, boilers used in commercial establishments, medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water. Waste heat boilers are excluded from this definition. The Process Heaters source category includes, but is not limited to, secondary metals process heaters, and petroleum and chemical industry process heaters. A process heater is defined as an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (*e.g.,* glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition. A boiler or process heater combusting solid waste is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the CAA.

TABLE 3—SOURCE CATEGORIES AFFECTED BY THIS FINAL ACTION

Source category	NESHAP	NAICS code [1]	Examples of regulated entities
Any industry using a boiler or process heater as defined in the final rule.	Industrial, Commercial, and Institutional Boilers and Process Heaters.	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.

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action is available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/stationary-sources-air-pollution/industrial-commercial-and-institutional-boilers-and-process-heaters.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the action and key technical documents at this same website.

A redline version of the regulatory language that incorporates the finalized changes in this action is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2002–0058).

D. Judicial Review and Administrative Reconsideration

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by December 5, 2022. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. This section also provides a mechanism for the EPA to reconsider the rule if the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within the period for public comment or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule. Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, WJC South Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Background

On March 21, 2011, the EPA established final emission standards for ICI boilers and process heaters at major sources, reflecting the application of the maximum achievable control technology (MACT) (76 FR 15608). On January 31, 2013, the EPA promulgated final amendments (78 FR 7138), which were challenged by industry and environmental petitioners. On November 20, 2015, the EPA promulgated additional amendments (80 FR 72789) in response to certain reconsideration issues.

On July 29, 2016, the D.C. Circuit issued its decision in *U.S. Sugar Corp* v. *EPA.* In that decision, the court upheld the EPA's 2013 final rule against all challenges brought by industry petitioners, and virtually all challenges brought by environmental petitioners. However, the court vacated the MACT floor emission limits for those subcategories where the EPA had excluded certain units from its MACT-floor calculation because those units burned less than 90 percent of the subcategory defining fuel. *U.S. Sugar Corp.* v. *EPA,* 830 F.3d at 631. As the court explained, ''[a]lthough the EPA allowed sources that combust only *10 per cent* of a subcategory defining fuel to join that subcategory, it declined to consider emissions from any source that burned *less than 90 per cent* of the subcategory-defining fuel when determining the average emissions level of the best performing sources in setting MACT floors for existing sources. And when it set a subcategory's MACT floors for new sources, the Agency declined to consider the emissions levels from any source that did not burn *100 per cent* of the fuel.'' *Id.* Because of this, ''several sources excluded from the MACT floor determination were among the best performing sources (or, in some cases, the single best performing source) in that fuel-based subcategory.'' *Id.* The court concluded that because the Clean Air Act requires the EPA to ''set the MACT floor at the level achieved by the best performing source, or the average of the best performing sources, in a subcategory,'' when ''the EPA includes a source in a subcategory, it must take into account that source's emissions levels in setting the MACT floor,'' no matter what percentage of subcategory-defining fuel that source burns. The D.C. Circuit therefore ''vacate[d] the MACT standards for all major boiler subcategories that would have been affected had the EPA considered all sources included in the subcategories.'' *Id.* at 632.

The D.C. Circuit subsequently granted EPA's motion for rehearing on remedy, withdrew its vacatur, and instead remanded for the EPA ''to identify those standards for which the MACT floor would have differed if the EPA had included all best-performing sources in each subcategory in its MACT-floor analysis'' and to ''revise those standards consistent with our July 29, 2016 opinion in this case.'' 844 F.3d at 270. Therefore, these standards have remained in effect since the court's decision.

The court in *U.S. Sugar* also remanded the use of CO as a surrogate for non-dioxin organic HAP to the EPA for the limited purpose of addressing public comments on the potential availability of post-combustion control technologies that could control CO. *Id.* at 628–30. As the D.C. Circuit explained, ''the EPA used carbon monoxide (CO) as a surrogate for several non-dioxin/furan organic HAPs when the Agency set the MACT floors for major boilers. In support of this approach, the EPA found that both CO and these HAPs were the products of 'incomplete combustion.' The Agency concluded as a result that CO was a reasonable surrogate because: (1) minimizing CO emissions would minimize these HAPs; (2) methods used for the control of these HAP emissions would be the same methods used to control CO emissions (*i.e.,* good combustion or using an oxidation catalyst); (3) standards limiting CO emissions would result in decreases in these HAP emissions; and (4) establishing emission limits for individual organic HAPs would be impractical and costly.'' *Id.* at 628 (citing 2010 Proposed Major Boilers Rule, 75 FR 32018). The environmental petitioners argued ''that the EPA has not adequately explained how setting emission standards for CO will . . . set emission standards for organic HAPs at the average level achieved by the best performers with regard to those HAPs.'' *Id.* The D.C. Circuit agreed, concluding that ''during notice and comment, the EPA failed to directly consider and respond to several comments that introduced evidence suggesting that other control technologies and methods could be effectively used to reduce HAP emissions without also impacting CO emissions, or vice versa.'' *Id.* at 629.

In a subsequent decision on March 16, 2018, the D.C. Circuit remanded the EPA's decision to set a limit of 130 ppm CO as a surrogate for non-dioxin organic HAP for certain subcategories, asking the Agency to better explain its analysis supporting its decision. *Sierra Club* v. *EPA,* 884 F.3d 1185. As the D.C. Circuit explained, in promulgating ''regulations that indirectly control a group of organic pollutants by limiting carbon monoxide emissions as a proxy for the targeted pollutants,'' and ''[a]fter calculating emissions limits for the organic pollutants by reference to the amount of carbon monoxide emitted by the best performing boilers in each subcategory, EPA concluded that the lowest of the carbon monoxide limits were too low, so it substituted a single, higher limit that it deemed sufficient to control the pollutants.'' *Id.* at 1189. The D.C. Circuit concluded that the ''EPA did not adequately justify its change of direction on the carbon monoxide limits because it failed to explain how the revised limits would minimize the targeted pollutants to the extent the Clean Air Act requires.'' *Id.* On August 24, 2020, the EPA published a notice of proposed rulemaking (NPRM) to address these issues remanded by the D.C. Circuit, and to make several technical clarifications and corrections (85 FR 52198). Section 112 of the CAA establishes a regulatory process to address emissions of hazardous air pollutants (HAP) from stationary sources. CAA section 112(d) requires the Agency to promulgate technology-based national emission standards for hazardous air pollutants (NESHAP) for major sources. ''Major sources'' are defined in CAA section 112(a) as sources that emit or have the potential to emit 10 tons or more per year (tpy) of a single HAP or 25 tpy or more of any combination of HAP. For major sources, the technology-based NESHAP must require the maximum degree of reduction in emissions of HAP achievable (after considering cost, energy requirements, and non-air quality health and environmental impacts). These standards are commonly referred to as MACT standards.

The MACT ''floor'' is the minimum control level allowed for MACT standards promulgated under CAA section 112(d)(3) and may not be based on cost considerations. For new sources, the MACT floor cannot be less stringent than the emissions control that is achieved in practice by the best controlled similar source. The MACT floor for existing sources may be less stringent than floors for new sources but may not be less stringent than the average emissions limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources). In developing MACT standards, the EPA must also consider control options that are more stringent than the floor (*i.e.,* ''beyond-the-floor'' options) under CAA section 112(d)(2). The EPA may establish beyond-the-floor standards more stringent than the floor based on considerations of the cost of achieving the emission reductions, any non-air quality health and environmental impacts, and energy requirements.

III. Summary of Final Action and Significant Changes Since Proposal

In this action, we are finalizing amendments to certain emission limits for new and existing boilers and process heaters. Most of these changes are identical to the emission limits that were proposed. As discussed further below at sections III.A.3 (HCl) and III.A.4 (PM), three of the emission limits have been revised since proposal following consideration of public comments received—New-Solid (HCl), New-Liquid (HCl), and Existing-Biomass Fluidized Bed (PM). We are also providing additional explanation to support the use of CO as a surrogate for organic HAP and to set a minimum CO emission limit of 130 ppm. In addition, we are finalizing approval of an alternative monitoring provision allowing for use of CO_2 as a diluent in lieu of O_2 when a continuous emission monitoring system (CEMS) is used to comply with an emission limit. We are also finalizing a small number of technical corrections based on our proposed action and our consideration of public comments received.

A. Revisions to MACT Floor Emission Limits

On July 29, 2016, the D.C. Circuit issued its decision in *U.S. Sugar Corp* v. *EPA.* In that decision, the court vacated those MACT limits where it held that the EPA had improperly excluded certain units in establishing the emission standards. Specifically, the court vacated all MACT limits where the EPA had included certain units in a subcategory but excluded those same units from its assessment of the subcategory's best performing sources. On December 23, 2016, the D.C. Circuit amended its July 29, 2016 decision, remanding those limits instead of vacating them, and ordering the Agency ''to identify those standards for which the MACT floor would have differed if the EPA had included all best-performing sources in each subcategory in its MACT-floor analysis'' and to ''revise those standards consistent with our July 29, 2016 opinion in this case.'' 844 F.3d at 270.

Prior to the *U.S. Sugar* decision, on August 20, 2013, the D.C. Circuit issued its decision in *National Ass'n. of Clean Water Agencies (NACWA)* v. *EPA,* which addressed challenges to the EPA's 2011 Sewage Sludge Incinerator (SSI) rule, issued under section 129 of the CAA. In *NACWA* v. *EPA,* the court remanded the EPA's use of the upper prediction limit (UPL) methodology to the Agency for further explanation of how the methodology reflected the average emissions limitation achieved by the best-performing 12 percent of sources (for existing sources) and the average emissions limitation achieved by the best-performing similar source (for new sources). *NACWA* v. *EPA,* 734 F.3d 1115, 1151. Because the UPL methodology used in the SSI rule was the same as that used in the Boiler Rule, the EPA requested a remand of the record in *U.S. Sugar* v. *EPA* in order to address the court's decision in *NACWA* v. *EPA.* The EPA prepared a memorandum explaining the methodology for the UPL, *EPA's Response to Remand of the Record for Major Source Boilers,*[2] that provided a detailed rationale to use the UPL as the basis of setting a MACT floor for new and existing sources. The methodology and the explanation in the memorandum were upheld by the D.C. Circuit in *U.S. Sugar* v. *EPA.* 830 F.3d at 639.

Accordingly, the EPA is finalizing changes to emission limits for new and existing boilers and process heaters. These changes address the court's concern regarding co-firing units that were included in a subcategory but excluded from consideration of that subcategory's best-performing sources in the 2013 analysis. In addition, these changes apply the UPL to the MACT floor analysis for limited datasets as explained in EPA's August 2019, memorandum titled ''Approach for Applying the Upper Prediction Limit to Limited Datasets for Boilers and Process Heaters at Major Sources.''

1. Overarching Methodology and Dataset Basis

In the 2020 proposal, the EPA based its revised analysis to address the remand on the same dataset used as the basis for the 2013 final rule.[3] [4] The 2013 final rule incorporated electronic reporting requirements into the rule. As a result, numerous emission test reports and other compliance data are now available through the Compliance and Emissions Data Reporting Interface (CEDRI) and WebFIRE.[5] However, since the revisions to the MACT floor analysis were conducted solely to address the remand in *U.S. Sugar* by correcting the calculations the court found impermissible, the EPA did not update its dataset to incorporate CEDRI compliance data into its revised MACT floor analysis.

While the EPA proposed to maintain the same dataset basis as the 2013 rule, the revisions to the rankings of emissions information to identify the best-performing units to include in the MACT floor calculation[6] required that the EPA conduct a more detailed review of the data available for the units in the dataset that had previously been excluded from the rankings, focusing on the newly identified best performers in

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[2] See Docket ID Item No. EPA–HQ–OAR–2002–0058–3892.

[3] See 85 FR 52203.

[4] Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, and Fuel Analysis Data Reporting under ICR No. 2286.01 and ICR No.2286.03 (OMB Control Number 2060–0616) (version 8). See Docket ID Item No. EPA–HQ–OAR–2002–0058–3830.

[5] U.S. Environmental Protection Agency. Compliance and Emissions Data Reporting Interface (CEDRI) *https://www.epa.gov/electronic-reporting-air-emissions/cedri* and WebFIRE database *https://www.epa.gov/electronic-reporting-air-emissions/webfire.*

[6] See Docket ID Item No. EPA–HQ–OAR–2002–0058–0815 for background on how the EPA calculates MACT emission limits, along with the docketed memorandum, *Revised MACT Floor Analysis (2021) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source.*

the 2020 proposal. While reviewing the underlying emissions test reports, the EPA corrected some database errors, filled information gaps on relative heat inputs from individual fuel types for certain co-fired fuel blends in order to verify that units did indeed belong to a specific fuel subcategory based on background combustion process information provided in the test reports or database fuel heat input background tables, and adjusted CO instrument span measurements since some of the revised rankings showed test run values that were incorrectly reported as zero, non-detect, or negative in the database. The CO instrument span establishes the appropriate representative detection level (RDL) to use in the MACT floor calculations and the underlying emissions test reports in the record typically contained the span information. In some cases, when the span information was not available, default span values were assigned as discussed in the memorandum, *Incorporating Measurement Error in Reported Carbon Monoxide (CO) and Total Hydrocarbon (THC) Data (Revised August 2012).*[7] These adjustments were needed to ensure that we could use the data from the newly identified best performers. Had these units been identified as best performers in the original rulemaking, the EPA would have conducted a similar review of the test data and made the same corrections and adjustments. These data had not been previously scrutinized since they were not used in the original UPL calculations. While corrections were made to the original dataset for the purposes of revising UPL calculations for this final rule, no recent compliance data after January 31, 2013 (*e.g.,* emission test reports and other compliance data available through CEDRI and WebFIRE) were incorporated into the rankings or UPL calculations for these final MACT floor emission standards, for the reasons explained later in this subsection.

Commenters both agreed and disagreed with the EPA's use of the original 2013 dataset for this reanalysis of the emission limits. Some commenters provided limited, specific examples of where they believed additional data should be incorporated to provide additional emission test run variability in cases where there are limited datasets. However, these same commenters also agreed that EPA's use of the 2013 dataset is reasonable. These commenters pointed out that the court's decision in *U.S. Sugar* directed the EPA to correct its analysis of the 2013 dataset that established the emissions standards, not to collect new data.

Another commenter disagreed with the proposed approach to base the revisions to the MACT floor analysis on data from the 2013 final rule. The commenter claims the data is obsolete and ignores several years of compliance data available in CEDRI. This commenter did not dispute the EPA's methodology in calculating revised MACT standards consistent with the D.C. Circuit's opinion in *U.S. Sugar* v. *EPA.* The commenter's criticism was that the EPA should have considered additional data beyond those contained in the 2013 database for the remanded rule, and they claimed that, in fact, section 112(d) of the CAA requires the Agency to consider compliance data in its action on remand.

Another commenter also requested that the EPA consider certain additional data. The commenter stated that, ''it is appropriate to include only information that is relevant for setting the floor or identifying appropriate variability and exclude data that represents post-promulgation changes made to existing sources,'' [8] and that including the latter data would inappropriately redefine a standard based on actions taken to comply with such standard. However, the commenter believes that the EPA should not ignore units for which it has emissions information without justifying why the result from more limited data is sufficient. The commenter cites section 112(d)(3)(A) of the CAA, which requires that the MACT floor be no less stringent than the average emission limitation achieved by the best performing 12 percent of the existing sources for which the Administrator has emissions information.

The commenters claiming that the EPA must consider on remand additional data beyond the 2013 dataset that was used to establish the 2013 standards which were before the court misconstrue the D.C. Circuit's instructions in its decision remanding those standards to the EPA. The court stated that on remand, the EPA must ''identify those standards for which the MACT floor would have differed if the EPA had included all best-performing sources in each subcategory in its MACT-floor analysis.'' *U.S. Sugar* v. *EPA,* 844 F.3d 268 (2016) (granting EPA's motion for rehearing). The court further instructed the EPA to ''revise those standards consistent with'' the court's opinion. *Id.* Nothing in the court's opinion or in its grant of rehearing instructs or requires the EPA to initiate a new standard-setting process or to assemble additional data. Rather, the remand was targeted to *only* those standards affected by the court's decision, and the court did not address the question of whether the EPA should—let alone must—consider data that did not exist at the time the challenged rule was issued. In contrast, the D.C. Circuit vacated—rather than remanded—the EPA's 2004 emissions standards for commercial and industrial boilers because it anticipated a ''wholesale revision'' of the rule would be required. *NRDC* v. *EPA,* 489 F.3d 1250, 1262 (2007). Here, the court neither vacated the standards, nor indicated that it anticipated consideration of additional data.

The EPA further disagrees that section 112(d)(3)(A)'s reference to sources ''for which the Administrator has emissions information'' requires consideration of additional data beyond the 2013 dataset, such as compliance data. That qualifying language is intended to ensure that the EPA need not obtain emissions data from 100 percent of the source category or subcategory in order to identify the best performing 12 percent of the source category, consistent with the overall Congressional intent in enacting the 1990 amendments to section 112 to prevent delay in regulating emissions of hazardous air pollutants. Rather, the EPA could identify the best performing 12 percent of the sources for which it had emissions data, even if the Agency did not have emissions data for all the sources in the source category or subcategory and could set standards on that basis without having to collect information from all sources. In other words, the language the commenter refers to does not compel collection or consideration of additional data, particularly here, where the EPA is revising standards solely in response to a court remand on a very specific, limited issue. The EPA further notes that some commenters would have the EPA selectively consider additional data, such as data showing additional variability. For example, one commenter claims that the EPA must consider compliance data only for the purpose of accounting for variability, but not otherwise. The EPA does not agree that it would be reasonable or appropriate to consider compliance data only to account for additional variability. Where the EPA uses data for the UPL calculation, it uses that data for purposes of calculating the floor as well as for accounting for variability, and it

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[7] See Docket ID Item No. EPA–HQ–OAR–2002–0058–3833.

[8] See Docket ID Item No. EPA–HQ–OAR–2002–0058–3969.

would not be appropriate to take a different approach here. As explained above, in this action the EPA is only correcting the flaw in its 2013 final rule analysis identified by the *U.S. Sugar* court in response to the court's remand. Further, while this action is limited to the remand, the Agency disagrees that, as a general matter, data representing compliance actions taken by sources to meet a previous standard are necessarily inappropriate to consider when revising a standard. However, that question is not at issue here.

The EPA's approach is reasonable given the limited nature of the remand. In addition, if the EPA were to revise the affected standards using newer emissions information, it could result in the potentially inequitable outcome of some units being subject to more stringent standards solely because of the EPA's error in its initial MACT floor calculations, while other units unaffected by the court decision would remain unchanged. Revising all of the boiler MACT standards, including the standards that have not been remanded, would require EPA to incur a significant resource burden and could result in wholesale changes to standards that were largely upheld by the D.C. Circuit. Given its other obligations under the statute and the EPA's determination that using new data is unnecessary to respond to the remand, the EPA has chosen to maintain the original data set for purposes of calculating standards. The revisions incorporate the co-fired boilers that met the subcategory definition using a threshold of at least 10 percent of a subcategory-defining fuel, on an annual heat input basis, but were excluded from the ranking analysis in the 2013 final emission standards. The D.C. Circuit in *U.S. Sugar* stated that, if the EPA includes a source in a subcategory, it must consider whether any source in that subcategory is a best-performing source which would then need to be accounted for in setting the MACT floor. *U.S. Sugar* v. *EPA,* 830 F.3d at 631. The final standards fully incorporate these sources in the development of standards as required by the remand.

2. UPL Methodology for Limited Datasets

Some of the MACT floor emission limits the EPA proposed were based on datasets with less than 7 test runs (''limited datasets''). There were limited datasets for the following subcategories and pollutants for both existing and new sources: process gas (Hg, HCl, total selected metals (TSM), and PM), biomass suspension burner (TSM), dry biomass stoker (TSM, PM, and CO), and coal fluidized bed coal refuse (CO). Limited datasets also existed for the following subcategories and pollutants for new sources: solid (Hg and HCl), liquid (Hg and HCl), heavy liquid (TSM and PM), light liquid (TSM and PM), biomass dutch oven/pile burner (TSM), biomass fuel cell (TSM), biomass fluidized bed (TSM), biomass suspension burner (TSM), biomass suspension grate (CO), wet biomass stoker (TSM), and coal (TSM and PM). On remand, these limited datasets were reviewed in additional detail to determine whether it was appropriate to make any modifications to the UPL approach used to calculate the MACT floors.

In addition to the proposed MACT floors involving limited datasets, the EPA also conducted a similar, more detailed review of the new source standards to evaluate if the UPL calculations required any adjustments to ensure that the resulting emission standards for new sources were not less stringent than for existing sources. Based on this review, the EPA found that the revised emission limits for three new source subcategories and pollutants did not reasonably account for variability and some changes were made to be consistent with *EPA's Approach for Applying the Upper Prediction Limit to Limited Dataset Boiler and Process Heaters at Major Sources* [9] to avoid the anomalous result the Court identified in *NACWA* v. *EPA* [10] where the calculated new source floor was less stringent than the existing source floor: These new source subcategories and pollutants are the following: solid (HCl), wet biomass stokers (TSM, PM), and biomass fluidized beds (PM).

The only comments received on the proposed methodology for analyzing limited datasets were made in the context of the new source solid fuel HCl emission limit. Those comments are summarized in section III.A.3 of this preamble.

The EPA is finalizing limited revisions to certain standards to address the specific issue identified by the court in *NACWA* v. *EPA*. The EPA is finalizing, as proposed, adjustments needed to three new source standards—Solid (HCl) and wet biomass stokers (TSM, PM), and biomass fluidized beds (PM)—to ensure that the new source floor is no less stringent than the existing source floor.[11] Additional detail about the determinations made at proposal are discussed in the docketed memorandum and no further analyses were needed as part of the final rule.[12]

3. Solid and Liquid Fuel HCl Emission Limits for New Sources

The proposed emission limits for HCl in the new source solid fuel and liquid fuel subcategories were both based on a value equal to 3 times the representative detection level (RDL) because the calculated UPL from the best performing similar source was less than this value.[13] In each case, the RDL value established for these two subcategories was based on the sampling times of the single best performer in each subcategory. For HCl, the detection level decreases with longer sampling times. For liquid fuels, the best performer had a 4-hour stack test, resulting in a 3 times RDL (3x RDL) of 5.4E–05 lb/MMBtu. For solid fuels, the best performer had a 1-hour stack test with an average oxygen concentration of 10.2 percent, resulting in a 3x RDL of 3.0E–04 lb/MMBtu.

In the case of liquid fuel boilers, the 3x RDL value was multiplied by a fuel variability factor to establish the MACT floor because the best performing unit had paired test data and fuel analysis data [14] to compare to fuel analysis used at the unit over time. The EPA also reviewed the data for the best performer in additional detail given that this best performing unit, ''LAShellChemicaGeismar, Furnace F–S801,'' had a limited dataset of 3 test runs. The EPA concluded that this unit was indeed a best performing unit.[15]

In the case of solid fuel boilers, the EPA proposed that the unit with the second lowest emission test results but the lowest variability, ''TXDibollTemple-Inland, PB–44'' (PB–44) was the best performing similar source.[16] This unit did not have paired test data and fuel analysis data to develop an appropriate fuel variability factor, so no fuel variability factor was applied to this emission limit.

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[9] *See* Docket ID Item No. EPA–HQ–OAR–2002–0058–3946.

[10] *See National Assn. of Clean Water Agencies* v. *EPA (NACWA)* 734 F 3d 1115.

[11] See 85 FR 52205–52207.

[12] See Docket ID Item No. EPA–HQ–OAR–2002–0058–3946.

[13] In cases where the calculated UPL value is less than three times the representative detection level (3x RDL), where the RDL is the average detection level of the best performing sources, the limit is determined to be equivalent to the 3x RDL value. Such a limit ensures measurement variability is addressed and provides a limit that has a measurement imprecision similar to other EPA test methods.

[14] Paired fuel and testing data means that there is an analysis of the fuel that was being utilized during the emissions testing. Unpaired fuel data may be representative of fuel burned at the unit, but not specifically the fuel burned during the emissions testing.

[15] See 85 FR 52206.

[16] Ibid.

Comment: Two commenters stated that the 3x RDL emission limit for HCl should have been calculated differently. One of the commenters provided specific suggestions, indicating they believed it is not appropriate for the EPA to set a RDL based on the operation of the top performing boiler alone. The commenter suggested that a more representative approach to setting a detection limit would be to derive an RDL associated with all non-detect emission tests for the best-performing units in the subcategory.

Response: The EPA agrees with the commenter that sample time data should be analyzed for the entire top 12 percent of units, not just the single best performer. However, the EPA disagrees with the commenter's suggested approach which considers only data that were reported as non-detect (*i.e.,* the emissions results were below the detection level of the instrumentation) instead of all available reported pollutant-specific method detection levels from the best performing units in each subcategory. As we stated in the docketed memorandum, *Data and Procedure for Handling Below Detection Level Data in Analyzing Various Pollutant Emissions Databases for MACT and RTR Emission Limits (Revised 2012),* our approach, ''minimizes . . . effect of a test(s) with an inordinately high method detection level (*e.g.,* the sample volume was too small, the laboratory technique was insufficiently sensitive, or the procedure for determining the minimum value for reporting was other than the detection level).'' [17]

Therefore, the EPA revised the 3x RDL values for new source solid and new source liquid HCl 3x RDL to reflect data from the top 12 percent of boilers. The data were pulled from the 2013 dataset and supporting test report files from the docket from the 2013 final rule. Revised data and analysis for the 3x RDL values are found in the docketed memorandum *Revised (2021) Analysis of Minimum Detection Levels from Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source.* The revised methodology and changes to the underlying data used for the 3x RDL calculations resulted in a 30 percent lower 3x RDL value than what was proposed for solid fuels, with the 3x RDL decreasing from 3.0E–04 to 2.1E–04 lb/MMBtu. For liquid fuels, the revised 3x RDL value is 122 percent higher than what we proposed, increasing from 5.4E–05 to 1.2E–04 lb/MMBtu.

Comment: Several commenters disagreed with the EPA's approach and rationale for selecting PB–44 as the best performing source for new solid fuel units, arguing that the solid fuel HCl limit calculations need to better account for natural variability in biomass fuel chloride levels as well as operational variability. Commenters noted that PB–44 only has a single three run test and it has a homogenous dry biomass fuel, sourced from on-site particleboard byproducts.

Commenters differed in their suggestions for what unit should be the best performing similar source. Some commenters suggested that Wellons Boiler was the best performing boiler, despite the larger variance in its HCl emissions. Some commenters made suggestions on how to adjust the Wellons Boiler data with additional data outside of the 2013 dataset. Other commenters suggested that other units in the top 12 percent for existing solid fuel HCl best performers were better choices than PB–44.

With regards to fuel variability, some commenters noted that PB–44 has only three test runs available and that a dataset with six test runs is superior to a dataset with three. One commenter also added that both PB–44 and Wellons Boiler do not have any HCl add-on control devices and the variation in emissions is directly related to fuel chloride content. The commenter argued that if the EPA had more data for PB–44, the variability in its HCl emission rates might be much higher and noted that variability can be determined more accurately with more test runs. This commenter also emphasized that the emissions of HCl at the lowest emitting unit are related to chloride variability in the fuel and not to the performance of any add-on control device. The commenter suggested several ways to better incorporate chloride variability in biomass fuels in its detailed comments.

One commenter further disagreed with the EPA's selection of PB–44 which had the second lowest emission test as the best performing similar source in its limited dataset analysis because it has lower variance in test results. The commenter suggested that variance is not the only consideration in the selection of a best performing similar source, especially where emissions are dictated by the fuel chloride variability and not by the use of a control device. This commenter also suggested that the EPA's selection of PB–44 to establish the new-source floor directly contradicts its assessment of long-term fuel variability by ignoring data related to fuel variability the Agency had previously argued was necessary. This commenter also suggested that the EPA's decision to finalize a standard based on limited dataset with only the UPL adjustment would be arbitrary, given that the fuel content must be taken into account to determine the emissions level that boiler actually achieved every day and under all operating conditions.

Response: The EPA disagrees with commenters that the PB–44 unit does not reflect the emissions control that is achieved in practice by the best controlled similar source. As discussed in section III.A of this preamble, the court remanded for further explanation the UPL methodology in *NACWA* v. *EPA,* in part for the EPA to explain how the UPL was appropriate for limited data sets in the face of the ''apparently illogical'' results where the emission limit for new sources was less stringent than the emission limit for existing sources. *NACWA* v *EPA,* 734 F.3d at 1144. Following the *NACWA* decision, the EPA issued the UPL memo and the limited data sets memo to provide the explanations requested by the court, and both approaches have been subsequently upheld by the D.C. Circuit. The EPA has applied the UPL and the limited data set approach in calculating the solid fuel HCl limit. The EPA could not determine that the Wellons Boiler, which commenters point out has more test runs available than the PB–44 unit, was the best performing similar source because it yielded the same ''apparently illogical'' result that the *NACWA* court questioned, *i.e.,* a new source limit that would be less stringent than the corresponding existing source limit, due to the variance in its data. In such circumstances, the EPA's limited data set approach provides that the EPA will further evaluate the individual dataset to ensure that the uncertainty associated with it does not cause the emissions limit to be so high that it does not reflect the emissions performance of the best performing similar source, for new source MACT standards.

Moreover, the EPA has broad discretion to identify best performing sources, and it is reasonable to consider variability in emissions when choosing the ''best'' sources from an emissions perspective. For example, a source could have the lowest average emissions level based on a single very low data point, but other very high emissions points. It is reasonable for the EPA to consider, in that circumstance, that a second source with a slightly higher average emissions level but consistently low emissions is a ''better'' performer

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[17] See Docket ID Item No. EPA–HQ–OAR–2002–0058–3839.

than the first source. Consistent with the previous MACT floor methodology, the EPA has determined that MACT floors based on a single source must be based on at least three runs of test data to ensure that adequate variability can be incorporated. The EPA has not thrown out other MACT floor emission limits that are based on a single three run test.[18] PB–44 has three valid test runs and it is the unit with the second lowest emissions test average results but has a variance that is 5 times lower than the Wellons boiler, and it did not yield a new source limit that is less stringent than the existing source limit. Therefore the EPA continues to conclude PB–44 is the best performing similar source for new solid fuel units.

The EPA further disagrees with commenters that it should incorporate fuel variability into the revised emission limit by evaluating fuel variability from other units in the 2013 dataset. We have previously stated that we can only apply a fuel variability factor when we have paired test data and fuel analysis data.[19] PB–44 had no paired fuel analysis data with its single 3-run HCl emission test in the 2013 dataset, so a fuel variability factor could not be developed according to the historical methodology used in the Boiler Rule.

The solid fuel subcategory encompasses a wide variety of boilers and process heaters and many of these units have achieved this emission level in practice, though each unit, depending on facility- and unit-specific circumstances, may employ different fuel blends and control devices to do so. Both the revised CEDRI compliance dataset and the 2013 dataset used to establish the MACT floor calculations present several examples of units in the solid fuel subcategory that have achieved this limit in practice. According to compliance data submitted to EPA via CEDRI through December 31, 2020, most of the new units in the solid fuel subcategory are meeting this more stringent emission limit that is based on a 3x RDL value.[20] Of the new units with test data, 71 percent (10 of the 14 units with HCl compliance test data) are meeting the revised 3x RDL value.

The EPA also disagrees with some of the commenter suggestions to bring in new data from outside the 2013 dataset to serve a targeted purpose for this single subcategory. The EPA explains earlier in this document why the Agency is not required to consider new data for purposes of this action.

4. Biomass Fluidized Bed PM Emission Limits for Existing and New Sources

For existing biomass fluidized beds, we proposed to make the PM emission limit more stringent, decreasing from 1.1E–01 to 2.1E–02 lb/MMBtu. The existing source floor was based on the top 5 units in the subcategory since the subcategory had fewer than 30 sources. The units that were part of the top 5 changed after we re-ranked the data to address the *U.S. Sugar* remand.

For new biomass fluidized beds, we also proposed to make the PM emission limit more stringent, decreasing from 9.8E–03 to 4.1E–03 lb/MMBtu. The unit with the lowest minimum test average was ''ORGeorgiaPacificWaunaMill, EU35—Fluidized Bed Boiler'' (Wauna boiler). The Wauna boiler had six separate tests in the boiler dataset. However, the calculated UPL for the Wauna boiler was 3.2E–02 lb/MMBtu, which exceeded the UPL calculated for existing units in the same subcategory, which was 2.1E–02. Since the new source floor was less stringent than the existing source floor, the EPA reviewed the data further to evaluate if the unit truly reflected the best controlled similar source and to evaluate if the UPL calculations required any adjustments to ensure that the UPL did not result in a less stringent standard for new sources. The EPA conducted additional analysis and determined that the unit with the second lowest minimum test, ''WIGPGreenBay2818, B10—Wastepaper Sludge-Fired Boiler 10'' (B10), was the best controlled similar source because it had a variance three orders of magnitude lower than the Wauna boiler and did not yield a limit less stringent than the existing source limit.

Comment: One commenter noted that the EPA included 15 p.m. emission tests for the unit LAGPPortHudson, EQT0109—No. 6 CFB Boiler (Port Hudson boiler), including two 2007 tests in which the dry scrubber was off for one test and on for the other, and the EPA only included data from the test where the scrubber was off in the UPL calculations. The commenter stated that both tests should be included in the UPL calculations.

Response: We reviewed the docket record to evaluate the commenter's concerns with the test runs included for the Port Hudson boiler. The Port Hudson boiler had five different tests included in the UPL calculations at proposal. Four of the five tests, dated September 11, 2007, December 18, 2008, December 19, 2008, and July 29, 2009, were all conducted with the sorbent injection system control device operating. The fifth test in August 2007 was conducted with the scrubber control device off. Given that the scrubber operating reflected the more common unit operations, we also evaluated CEDRI data for the purpose of verifying that the unit typically operates with its sorbent injection system operating. We disagree with the commenter that we should use the tests from August 2007 with both the sorbent injection control operating as well as off. Since this unit typically operates the sorbent injection system control device, only the tests conducted while this control device is operated are representative of the emission levels and typical operations employed by this source. Introducing statistical variability in UPL calculations by mixing test results for different control configurations would be inconsistent with the MACT floor methodology[21] since the unit typically conducts its compliance testing with the control system operating. When we evaluated the August 2007 test report available in the docket in more detail, we found that the August 2007 test report had four different test scenarios. Scenario 1 and 2 were the only scenarios firing biomass fuels (both fired a combination of biomass and petroleum coke, but met the threshold of at least 10 percent heat

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[18] *Revised MACT Floor Analysis (November 2011) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source.* Revised November 2011. See Docket ID Item No. EPA–HQ–OAR–2002–0058–3387.

[19] The EPA explained the limited nature of using only paired fuel variability data for the basis of its fuel variability factors in the original 2010 proposal. See *Maximum Achievable Control Technology (MACT) Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source.* See Docket ID Item No. EPA–HQ–OAR–2002–0058–0815. The EPA modified its approach slightly to address comments received on the proposed fuel analysis variability methodology as explained in the final rule (76 FR 15627) but never changed its fundamental criteria of looking only at paired fuel analysis data. As noted in the December 2011 reconsideration proposal, the EPA continued a consistent fuel variability methodology and at this juncture only ''[s]mall changes to fuel variability . . . to accommodate the new TSM standard and comments received during the reconsideration process'' were made, see Docket ID Item No. EPA–HQ–OAR–2002–0058–3387. When the EPA issued revised limits in the January 2013 final rule based on submitted data corrections or new data, it noted that the new data was incorporated that resulted in revised values, but the general MACT floor setting methodology remained the same (78 FR 7151).

[20] *Revised (2021) Methodology for Estimating Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants,* which is available in the docket for this action.

[21] Some facilities submitted emission test data based on previous control configurations that are no longer installed on the unit. Emission data reported while using these previous control configurations were not used to establish the MACT floor. See Docket ID Item No. EPA–HQ–OAR–2002–0058–3387.

input from biomass). The test scenario included in the proposal analysis had the sorbent injection system turned off. For the reasons discussed above, we replaced the August 2007 test with the test scenario which had the sorbent injection system turned on. After replacing this test scenario, the Port Hudson boiler was no longer part of the top five boilers in the existing source floor calculations. The Port Hudson boiler was removed from the existing source floor calculation because it had the eighth lowest mean emission test after reviewing and correcting the test scenarios used in the analysis, based on public comment. The boiler that now had the fifth lowest mean emission test is PAPHGlatfelter, PB5 (PB5 boiler), so we added the two emission tests from the PB5 boiler into the analysis for the UPL calculation for the existing source MACT floor.

Comment: Two commenters requested a data correction for the 2006 test from the Wauna boiler. The commenters noted that the PM test results in the 2013 dataset and MACT floor ranking were listed incorrectly as lb/MMBtu in the MACT floor analysis. They pointed to the supporting test report, where the values were actually in units of grains per dry standard cubic foot (gr/dscf), corrected to 7 percent oxygen, instead of lb/MMBtu. These commenters requested that the EPA revise the UPL calculation after correcting the units of measure for the 2006 test.

Response: We reviewed the docket record to verify the units of measure for the 2006 Wauna boiler test and agree with the commenters that a correction is needed to convert the gr/dscf into units of lb/MMBtu. We made this correction in the revised UPL calculation for both new and existing sources.

Comment: One commenter stated the Wauna boiler's 2004 stack test is an outlier and should be excluded from the data. The commenter stated that the EPA should remove this test and recalculate the UPL with the remaining 15 test runs from the Wauna boiler.

Response: We reviewed the 2004 Wauna boiler test that the commenter stated should be excluded to assess whether or not this test is in fact an outlier. The 2004 test had the same test method and length of the test runs as the other five tests. In addition, none of the other five tests subtracted negative filter weights or had weights less than 1 milligram. As the emissions limit is expressed in terms of emissions per heat input, we checked both the emissions and heat input data for outliers. Our general outlier test is conducted at the 5% significance level in log space, and when a value is found to be an outlier at this level, we exclude it from further calculations. We conducted an outlier test with ProUCL[22] and determined that none of the PM emission test runs had outliers, either in normal or in log space, at the 1, 5, and 10% significance levels. Observing that the heat input for the 2004 test was between 57 and 66 percent lower than the heat input for the other five tests in normal space, we conducted an outlier test with ProUCL and found that the total heat input for 2004 was an outlier at the 5 and 10% significance levels for both normal and log space. Because the heat input component of the 2004 emissions test is an outlier, we agree with the commenter that the heat input and the corresponding emissions value from this test should be excluded as an outlier. Therefore, we removed the 2004 test data from the UPL calculation for both new and existing sources.

After making the corrections to the 2006 Wauna boiler test, removing the outlier 2004 Wauna boiler test, and correcting for the appropriate tests for the Port Hudson boiler control device configurations, the existing source floor value calculations have changed since proposal. The revised emission calculations for existing sources considering these public comments and related data changes have resulted in a more stringent UPL calculation of 7.4E–03 lb/MMBtu.

Comment: One commenter requested that the EPA revise its determination for the best performer for the new source PM limit for biomass fluidized beds. The commenter noted that the EPA chose to base the new source floor on the second-best performing unit, despite having a more robust dataset for the top performer. The EPA selected the unit with the second lowest mean because it stated that the unit with the lowest mean (Wauna boiler) exhibited too much variance in its emissions data. The commenter noted that the dataset for the second-best performer (B10) offered only six test runs, while the Wauna boiler had 18 runs and better represented true variability at the unit. The commenter argued that the MACT floor should be based on the top-performing unit which utilizes the best control technology, a fabric filter, and pointed out that five of the six stack tests for the Wauna boiler exhibit consistent performance.

Response: Based on the data correction made for the units of measure for the 2006 test and removal of the 2004 test as an outlier, the calculated 99 percent UPL for the Wauna boiler decreased from the calculation in the proposed rule, from 3.2E–02 to 8.4E–03 lb/MMBtu. This revised UPL calculation for new sources still yields an anomalous result, as the new source PM limit is less stringent than the 7.4E–03 lb/MMBtu PM limit for existing sources.

Consistent with the 2020 proposal, the EPA conducted additional investigation of the revised Wauna boiler dataset to determine whether the Wauna boiler was indeed the best performing similar source. After determining the correct distribution and ensuring that we used the correct equation for the distribution, we evaluated the variance of this unit. Our analysis showed that this unit, identified as the best performing unit based on average emissions, has the highest variance among the top five performing boilers in the existing source floor, even after making the corrections for the 2004 and 2006 test data noted above. The variance is 7 times higher than the unit with the second lowest ranked mean, B10. The overall average (considering all stack tests, not just the minimum stack test average) for the Wauna boiler is also higher than the units with the second, third, and fourth lowest mean emission test results. The overall average for the Wauna boiler is 1.5 times higher than the second ranked unit, B10. This information indicates that the second ranked unit, B10, has a more consistent level of emissions performance than the Wauna Boiler, and the resulting UPL calculations support this. The calculated UPL is lower for B10 than for the Wauna boiler. For these reasons, we continue to conclude that the Wauna boiler is not the best performing source for this subcategory and pollutant and we are finalizing B10 as the best performing source. Therefore, the EPA is finalizing the proposed PM emission limit of 4.1E–03 lb/MMBtu for new sources.

More complete details of the revised analysis for both new and existing source PM emission limits are included in the docketed memorandum, *Revised MACT Floor Analysis (2021) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source.*

B. Beyond-the-Floor Emission Limits

We proposed beyond-the-floor limits for 16 subcategory and pollutant combinations. We compared the revised emission limits to the limits from the 2013 final rule to assess whether a beyond-the-floor option was technically achievable and cost effective. Typically

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[22] ProUCL is a comprehensive publicly available statistical software package. See *https://www.epa.gov/land-research/proucl-software.*

we would assess technical achievability and cost effectiveness by assessing various levels of stringency of emission reductions, technical achievability of options and associated costs. For this rule, for subcategories where the 2013 limit was more stringent than the MACT floor limit calculated in the 2020 proposal, we reviewed compliance data available through CEDRI and WebFIRE to assess whether the more stringent limit was being achieved in practice. There were nine subcategory and pollutant combinations for existing sources and seven subcategory and pollutant combinations for new sources where compliance data showed boilers that already achieved the 2013 limits. Then, to assess whether compliance with the 2013 limits was cost effective, we reviewed the control devices currently installed to determine if any cost savings would occur should we finalize the less stringent limit. In all cases, the controls that were already installed were the same types of controls that would be required to meet either the 2013 limits or the less stringent limits calculated in the proposed rule and, therefore, no additional costs would be incurred to meet the more stringent limits. As a result, we proposed 16 emission limits from the 2013 final rule as beyond-the-floor limits.

There were six limits in three subcategories—new and existing units for PM for Gas 2 units, TSM for biomass suspension burners, and TSM for dry biomass stokers—where the 2013 limits were more stringent than the MACT floor limits calculated for the proposed rule, but recent compliance data were not available. Since no data were available, we did not identify any beyond-the-floor options for these subcategories and beyond-the-floor limits were not proposed for these subcategories. For TSM, sources have the option to comply with either PM or TSM emission limits. The lack of available TSM data indicates that sources in these subcategories are all complying with the PM emission limits rather than the alternative TSM limits. The lack of available PM data for Gas 2 units indicates that sources are all meeting the Gas 1 subcategory definition.

Comment: One commenter suggested that the EPA's proposed approach for the beyond-the-floor analysis does not satisfy section 112(d)(2) of the CAA, which requires the ''maximum'' degree of reduction that is ''achievable'' considering cost and other factors through all potential reduction measures. The commenter noted that the EPA only considered whether the newly recalculated floors were less stringent than the emission levels that were already being achieved, and if ''no additional costs would be incurred to meet the more stringent limits,'' then the EPA set beyond-the-floor standards which are more stringent than the floors and are equivalent to the current standards that these boilers have already been meeting. The commenter acknowledged that the EPA is correct to recognize that the current limits are achievable but argued that the EPA's analysis does not actually consider what the ''maximum'' achievable reductions are, such as what reduction levels are achievable through use of cleaner fuels or control technologies.

This commenter also stated that it is unlawful that the EPA proposed to weaken six limits since all of the units subject to those limits have already been in compliance with them for more than three years. The commenter argued that any standards that are less stringent than the 2013 limits do not represent the average emission levels achieved by the relevant best performing units.

Response: We disagree with the commenter that the beyond-the-floor analysis does not satisfy section 112(d)(2) of the CAA. In 2013, the EPA conducted a subsequent beyond-the-floor analysis, evaluating whether any recalculated emission limits were less stringent than the 2011 rule in order to assess whether a beyond-the-floor option was technically achievable and cost effective. This analysis resulted in nine beyond-the-floor limits.[23] The beyond-the-floor analysis conducted in the proposal used the same methodology and resulted in 16 proposed beyond-the-floor limits.[24]

Most of the recalculated emission limits resulting from the *U.S. Sugar* remand resulted in more stringent limits compared to the 2013 final rule. For these limits, the EPA continues to believe the analysis in the 2011 rule is reasonable, and the EPA received no information during the comment period to demonstrate it is not. Further, for most affected standards where the EPA's recalculation of the UPL resulted in a less stringent numeric limit, the EPA is retaining the more stringent limit based on its authority to set standards beyond the MACT floor. This is a reasonable approach where sources have been complying with the 2013 standards, thus demonstrating that the standards are achievable, considering the factors enumerated in section 112(d)(2) of the CAA. The only exception to this approach is for alternative standards where there is no demonstration that any source has been complying with the standard since the 2016 compliance date because no units are in the subcategory or no units have chosen to utilize the alternative limits.

Based on this, additional analyses of compliance data, and the lack of information on additional control technologies provided by the commenter, we continue to believe that our beyond-the-floor analysis is appropriate, and we are finalizing the 16 beyond-the-floor limits as proposed.

We further disagree with the commenter that it is unlawful to finalize the six emission limits that were recalculated to be less stringent than the 2013 standards. First, the court in *U.S. Sugar* determined that the 2013 limits were incorrectly calculated and remanded the standards to the EPA. The recalculated MACT floors are a result of addressing deficiencies identified by the *U.S. Sugar* court and additionally by the *NACWA* decision on limited datasets. Second, we did not identify any beyond-the-floor options for these subcategories. We found that no biomass suspension burners or dry biomass stokers have been using the alternative TSM limit for compliance—all units have been complying with the PM limit. In addition, we found that no units have been subject to the PM limit in the Gas 2 subcategory and therefore have no information to conclude that additional reductions are achievable.

In addition, we note that while these six recalculated limits are slightly less stringent than the 2013 limits, in practice they are not effectively different. Affected sources would install the same control technology to meet either the remanded or the recalculated emissions limits, despite the slight increase in the recalculated limits. Furthermore, no emissions increases are expected to result from finalizing less stringent units in these subcategories since no sources exist that are subject to the Gas 2 limit, or that are choosing to meet the alternative TSM limits.

C. Revisions to Output-Based Emission Limits

In the proposed rule, the EPA re-calculated the corresponding output-based emission limits to update the limits in the fourth column of Tables 1 and 2 of the regulatory text. Revisions were not required for all the proposed emission limits due to rounding and the small amount of change in the corresponding input-based limit between the 2013 limits and the limits in the proposed rule. The memorandum,

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[23] See Docket ID Item No. EPA–HQ–OAR–2002–0058–3843.

[24] See Docket ID Item No. EPA–HQ–OAR–2002–0058–3948.

Alternate Equivalent Output-Based Emission Limits for Boilers and Process Heaters Located at Major Source Facilities—2019 Revision, which is available in the docket for this action, provides details of the output-based emission limit revisions and methodology.

We received no comments on the proposed changes to the output-based standards. Therefore, we are finalizing the revisions to the output-based emission limits as proposed. We have revised output-based emission limit calculations to reflect the changes made to the corresponding input-based emission limits for existing source biomass fluidized bed PM and new sources solid and liquid fuel HCl. The memorandum, *Alternate Equivalent Output-Based Emission Limits for Boilers and Process Heaters Located at Major Source Facilities—2021 Revision,* which is available in the docket for this action, provides details of the output-based emission limit revisions since proposal.

D. CO as a Surrogate for Organic HAP

On July 29, 2016, the D.C. Circuit issued its decision in *U.S. Sugar Corp* v. *EPA,* 830 F.3d 579. In that decision, the court remanded to the EPA to adequately explain how CO acts as a reasonable surrogate for non-dioxin/furan organic HAPs. To be reasonable, the emission standard set for the surrogate must reflect what the best similar source or the best 12 percent of sources in the relevant subcategory achieved with regard to the HAP. This requires the surrogate's emissions to share a close relationship with the emissions of the HAP. The court identified that one crucial factor for determining whether that close relationship exists is the availability of alternative control technologies that reduce the HAP emissions without impacting that of the surrogate or, conversely, reduce the surrogate emissions without impacting the HAP emissions. The court stated that the EPA could not conclude that CO acts as a reasonable surrogate in this statutory context without considering whether the best performing boilers might be using alternative control technologies and methods that reduce organic HAP emissions beyond what they achieve by reducing CO alone. The court asked that EPA address concerns raised in public comments that alternative control technologies might further lower HAP emissions.

In response to this remand, the EPA provided further explanation to substantiate its finding that CO is an appropriate surrogate for non-dioxin/furan organic HAP. In the proposed rule, the EPA noted that available control technologies for organic HAP emissions are either combustion devices or recovery devices. Combustion is the more commonly applied option for controlling organic HAP because it is capable of high removal (destruction) efficiencies and its effectiveness does not depend on the makeup of the organic HAP stream or the organic HAP concentration. Recovery devices are not applicable for all organic HAP and are not effective in treating low organic HAP concentration streams, *i.e.,* the levels of concentrations seen in sources with good combustion practices.

In the proposal, we indicated that none of the best-performing units employ an add-on, alternative control device that was installed for controlling emissions of either organic HAP or CO. While many industrial boilers and process heaters employ post combustion controls for particulate matter, acid gases, and/or mercury, these add on controls are not designed to affect emissions of either CO or non-dioxin organic HAP. In any case, any add-on controls that are downstream of the combustion chamber of the boiler would be secondary controls that would only be effective (if at all) if the upstream primary control (the combustor) was ineffective. The presence of CO in the flue gas stream is an indicator of inefficient and incomplete combustion. The presence of non-dioxin organic HAP (or other organic compounds) in the flue gas stream would also be an indication that the upstream combustion process was inefficient and incomplete (*i.e.,* perfectly complete combustion of an organic compound would result in only CO_2 as a carbon-containing product). The best performing industrial boilers do not employ downstream controls for CO or non-dioxin organic HAP because the primary control (the combustor) is effectively destroying the non-dioxin organic HAP and downstream controls are not needed to achieve additional reductions. Minimum CO concentration in the flue gas stream is evidence of that the combustion process is efficient and effective. For these reasons, the Agency continued to conclude that CO is a reasonable surrogate for non-dioxin/furan organic HAP.

Comment: Commenters stated that not all organic HAP are products of incomplete combustion. Some organic HAP—such as polychlorinated biphenyls (PCBs) and polycyclic organic matter (POM)—can be present in the raw materials before combustion or can be generated outside the combustion unit or within the combustion unit but outside of the flame zone. In addition, different organic HAPs can be formed, destroyed, or reformed in various physical regions of diffusion flames and in different zones of premixed flames. Commenters stated that minimizing CO emissions will not minimize emissions of all organic HAP other than dioxins and furans because not all organic HAPs are formed or destroyed in combustion and post-combustion zones in the same fashion or like CO. The commenters further claimed that underlying formation and destruction of just CO in the simplest of situations involves several hundred reactions and tens of individual species are involved. The kinetics and thermodynamics become far more complex for other organic HAPs. Thus, the commenters argued, there is no basis in combustion science to presume that even any one organic HAP—much less all of them will behave similarly to CO. Specifically, the commenters claimed, pollutants like PCBs and POM/polycyclic aromatic hydrocarbon (PAH) will not be minimized by good combustion or through using a post-combustion oxidation catalyst.

Response: We agree with the commenter that organic compounds—and perhaps even organic HAP—are present in the fuels (coal, biomass, *etc*) used in industrial boilers. With regard to the PCBs mentioned by the commenter, we note that PCBs are commonly known as ''dioxin-like'' organic compounds [25] and their formation should similarly be limited by the work practice standards established for dioxins and furans. Regarding the POM/PAH mentioned by the commenter, these compounds are well known to be products of incomplete or inefficient (*i.e.,* oxygen-starved or fuel-rich) combustion.[26] [27] [28] [29] [30] Similarly, CO is also the product of inefficient combustion. In an oxygen-rich environment, complete and efficient combustion will produce CO_2 rather than CO. Regardless of whether organic HAP are present in the boiler's fuel before combustion, or whether they are generated within the combustion unit, all organic HAP would be destroyed under complete and efficient

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[25] ''Dioxins'' are often described as ''dioxins, furans, and dioxin-like compounds''.

[26] Serban C. Moldoveanu, in *Pyrolysis of Organic Molecules* (*Second Edition*), 2019.

[27] T.A. Abrajano Jr., V. O'Malley, in Treatise on Geochemistry, 2007.''

[28] Z. Fan, L. Lin, in *Encyclopedia of Environmental Health (Second Edition),* 2011.

[29] M. Huang, T.M. Penning, in Encyclopedia of Food Safety, 2014.

[30] Tarek Saba, in *Introduction to Environmental Forensics (Third Edition),* 2015.

combustion conditions. Therefore, the presence of organic HAP in the boiler emission flue gas stream would be the result of incomplete combustion and higher emissions of CO (relative to CO_2) would be expected.

We also disagree with the comment that minimizing CO emissions will not minimize emissions of all organic HAP other than dioxins and furans. The Agency agrees that combustion is complex and involves many reactions causing many different organic compounds to form and be themselves combusted to form other organic compounds. Combustion is the process of breaking apart the organic (*i.e.,* carbon-containing) molecules in the fuel and converting them to CO_2. Perfectly complete combustion would convert all the carbon in the fuel to CO_2. Completeness of the combustion process is dependent on several variables, including the temperature, the amount of oxygen, and the mixing of the fuel and oxygen. Incomplete combustion results in production of partly broken down and partially oxidized organic compounds, including CO. Because the conversion of CO to CO_2 is a difficult step, and the last one in the destruction of hydrocarbons, including organic HAPs, the EPA concluded it is a good indicator of the completeness of combustion. Thus, decreasing levels of CO are correlated with increasing destruction of organic compounds until a threshold is reached where, because combustion of CO is the last step in combustion, the combustion of organic materials, including organic HAP, is essentially complete.

Comment: One commenter noted that boilers are frequently the primary control devices under many new source performance standards (NSPS) and NESHAP standards for control of emission streams containing organic compounds. Typically, vent gases containing organic HAP emissions are sent to boilers or process heaters as supplemental fuel if they have sufficient heating value, and boilers and process heaters are accepted as emission control devices because performance testing routinely shows that they can provide organic destruction efficiencies of greater than 98 percent. Nearly all boilers and process heaters use monitoring of CO as a means to evaluate whether the device is performing effectively, and when CO increases, the unit is not efficiently oxidizing CO to CO_2 and the organics are not being as effectively oxidized.

Response: We agree with the commenter that boilers have frequently been identified as the best way of reducing emissions of organic compounds. Combustion devices, such as boilers, continue to be identified as the best control option available for reducing organic HAP from various industrial processes.[31]

Comment: Commenters stated that organic HAP can be reduced not only through combustion controls but also through post-combustion controls such as fabric filters, wet scrubbers, and activated carbon injection (ACI). Commenters further stated that the EPA has found that ACI reduces emissions of all organic HAP by 80 to 90 percent. Commenters stated that this refutes the EPA's claims that the measures for controlling CO and organic HAP are the same.

Response: The EPA agrees that some downstream control devices have the capacity to reduce organic emissions. However, such downstream control devices are only effective if the primary control device—the combustor itself—is not effectively destroying the organic HAP before it reaches the downstream controls. Further, the effectiveness of the post-combustion techniques identified by the commenter, unlike thermal oxidation, depends specifically on the organic HAP and on the concentration of the particular organic HAP. The commenter noted that the EPA has previously stated that POM/PAH that is emitted during combustion can be further reduced by various post-combustion controls, including fabric filters, wet scrubbers, and ACI. However, as discussed previously, POM/PAH compounds are the product of incomplete and inefficient combustion. Therefore, if the combustor is optimized for combustion—as indicated by its CO emissions—then POM/PAH production will be minimized, and the downstream control equipment will be unnecessary.

We also disagree with the commenter that the EPA found that ACI reduces organic HAP emissions by 80 to 90 percent. The commenter is citing a telecommunication from an ACI vendor regarding organic HAP emissions from a sinter plant in the Integrated Iron and Steel Manufacturing source category, not a statement by EPA (85 FR 42090). In that action, for purposes of evaluating cost-effectiveness, the EPA assumed reductions at a level provided by the vendor but did not itself conclude that those reductions were achievable. The issue being addressed in the remand is whether the best performing units were using post-combustion controls that controlled organic HAP but did not control CO. None of the best performing boilers use an ACI system.

E. CO 130 PPM Threshold Emission Limits

On March 16, 2018, the D.C. Circuit issued its decision in *Sierra Club* v. *EPA,* 884 F.3d 1185. In that decision, the court remanded the EPA's decision to set a limit of 130 ppm CO as a surrogate for non-dioxin organic HAP for certain subcategories, asking the Agency to better explain its analysis supporting its decision. The court held that the EPA had not sufficiently explained its rationale and questioned EPA's reliance on data regarding the relationship between formaldehyde and organic HAP that the EPA had previously characterized as unreliable.

The court noted that if the EPA made and adequately supported a determination that no further reduction of HAP would occur once CO levels had been reduced to 130 ppm, the threshold would be appropriate and consistent with the CAA. The court noted three specific issues it believed the Agency did not adequately address: (1) the EPA gave no reason why organic HAP emissions could not be further reduced once CO emissions reach 130 ppm, (2) the EPA relied on formaldehyde data to support its conclusion but elsewhere stated that the same data were not a reliable indicator of organic HAP emissions at very low levels, and (3) the EPA did not adequately explain why 130 ppm is the appropriate level if there is a non-zero CO level below which organic HAP levels cannot be further reduced.

In response to this remand, the EPA provided further explanation to substantiate the 130 ppm threshold emission limit. In the proposed rule, we described the relationship that we previously found between CO and formaldehyde using the available data obtained during the 2013 rulemaking. The paired data showed decreasing formaldehyde emissions with decreasing CO emissions down to CO levels around 300 ppm (with formaldehyde emissions down to less than 1 ppm). A slight increase in formaldehyde emissions, to between 1 and 2 ppm, was observed at CO levels below around 200 ppm, suggesting a breakdown in the CO-formaldehyde relationship at low CO concentrations. At levels lower than 150 ppm, the mean levels of formaldehyde appeared to increase, as does the overall maximum value of and variability in formaldehyde emissions.

In the proposed rule, we corroborated our observation that reducing CO emissions also resulted in a reduction of

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[31] See, for example, 40 CFR part 63, subparts F, G, H, I, and FFFF.

formaldehyde emissions until a leveling off in formaldehyde reductions is reached after which further reduction of CO levels appeared to result in higher levels of formaldehyde emitted. The proposed rule described in detail two additional studies—the polycyclic aromatic hydrocarbons (PAH) study[32] and the Multipollutant Control Research Facility (MPCRF) study[33]—that observed this same trend. In addition, in the proposed rule, we suggested a potential explanation for this observed trend. As has already been discussed, near complete combustion (as evidenced by very low CO concentration) is possible under an oxygen-rich environment. To achieve that oxygen-rich environment, excess combustion air must be provided to the burners. As the combustion process progresses, the increased combustion air can increase the turbulence and mixing within the boiler. This increased turbulence can result in some molecules of the reactants (*i.e.,* the oxygen and organic HAP) being forced near the furnace walls which are somewhat colder than the combustion zone. This cooling, known as the ''wall effect,'' may be sufficient to impact the combustion reaction, resulting in some organic HAP molecules that are not fully combusted, and thus emitted.

In the 2013 rulemaking, we determined that there are no further reductions of organic HAP available below 130 ppm CO. This analysis relied on our paired CO-formaldehyde data, yet we also stated that the same data were not a reliable indicator of organic HAP emissions at very low levels. At that time, we were not aware of any reason why formaldehyde concentrations would increase as CO concentrations continue to decrease, indicating improved combustion conditions. Our thinking in 2013 was that imprecise formaldehyde measurements at low concentrations may have accounted for this slight increase in formaldehyde emissions observed at CO levels below 130 ppm. In the preamble of the 2013 final rule, we stated, ''[b]ased on this, we do not believe that such measurements are sufficiently reliable to use as a basis for establishing an emissions limit.'' 78 FR 7145. In that statement, we were referring to the formaldehyde measurements and, thus, to the decision to set a CO standard instead of a formaldehyde standard.

Our evaluation of the PAH and MPRCRF studies revealed that the observed relationship in our CO-formaldehyde data was not due to imprecise or unreliable measurements, but in fact has been observed in other studies. Because the same CO–HAP relationship was presented in the PAH and MPCRF studies (*i.e.,* that organic HAP levels decreased with decreasing CO levels until a leveling off and trending upward with further decreasing CO levels), we concluded in the proposed rule that our formaldehyde data used in establishing the 130 ppm CO standard was not imprecise or unreliable and could be explained by the wall effect described above. These studies, combined with the relationship found in our CO-formaldehyde data, support that there is a non-zero CO level below which organic HAP levels are not further reduced.

Comment: One commenter opposed the EPA's claim that organic HAP are effectively nonexistent when CO levels are below 130 ppm. The commenter stated that the EPA's formaldehyde emissions data shows that there are significant formaldehyde emissions at CO levels below 130 ppm, at 2 ppm or more even with the limited data set available. The commenter also stated that the PAH study merely confirms that there are significant PAH emissions even at very high levels of excess air when CO levels would be expected to be very low. This data shows that gaseous PAH emissions actually increase with increasing excess air as it is increased from 20 percent to 40 percent—when CO levels would be dropping. The commenter further stated that the MPCRF study confirms that organic HAP emissions are not nonexistent when CO levels are at or below 130 ppm and that they are not correlated with CO.

Response: We disagree with the commenter that the *Sierra Club* decision requires the EPA to demonstrate that organic HAP emissions are ''nonexistent'' at the level of the CO standard. Rather, the court said that the standard based on a surrogate must be set at a level at which ''the EPA can be confident that the targeted HAP emissions are reduced as far as possible *or,* indeed, eliminated entirely.'' *Sierra Club,* 884 F.3d at 1195 (emphasis added). We agree with the commenter that organic HAP emissions can be non-zero when CO levels are below 130 ppm, but at that level, they are expected to be reduced to the greatest extent. Our CO-formaldehyde data for units operating at a CO concentration level below 130 ppm ranged from a measured high value of 2 ppm to a measured low value of 0.1 part per billion (ppb). The range of emissions from multiple tested units is expected due to inherent variability from unit-to-unit. In contrast, the data presented from the PAH and MPCRF studies were measured from a single unit (*i.e.,* each study used a single boiler for the tests). The MPCRF study shows the same trend with formaldehyde levels increasing from 10 ppb, at 70 ppm CO, to 57 ppb, at 40 ppm CO. The MPCRF study also shows that as the CO concentration levels at around 130 ppm, organic HAP, as a group, have been reduced to their minimum levels. Some of the organic HAP in the MPCRF study show the same trend as the PAH study and the EPA's CO-formaldehyde data. Some show no further reduction, but most of these also show a spike in concentration below 130 ppm CO. While some organic HAP did show further reduction, as stated earlier, as a group the organic HAP had been reduced to minimum levels by around 130 ppm. Based on the overall consideration of each of these organic HAP, we continue to conclude that there are no further reductions of organic HAP available below 130 ppm CO.

Comment: Commenters also disagreed with the EPA's statement that organic HAP cannot be further reduced when CO levels are below 130 ppm. The commenter stated that the EPA has recognized that all organic HAP emissions can be reduced with ACI, and some organic HAP emissions can also be reduced with other end-of-stack controls, including fabric filters and wet scrubbers.

Response: The EPA disagrees with the comment that organic HAP can be further reduced when emitted from a boiler with CO levels below 130 ppm. The level of organic HAP emitted, as indicated in the MPCRF study are in a range that is well below the inlet concentration of the post-combustion controls used for other pollutants. As discussed in the proposal preamble, Figure 4–16 of the MPCRF study shows the concentration of phenol, an organic HAP, plotted against concentration of CO. CO concentrations ranged from 40 to 140 ppm, at 7-percent oxygen, with phenol concentrations ranging from 0.6 parts per billion (ppb) at 40 ppm CO to 1 ppb at 140-ppm CO with the lowest phenol concentration (0.5 ppb) measured at 95-ppm CO (120-ppm CO at 3-percent oxygen). Concentrations of conventional pollutants (*e.g.,* NO_X, SO_2, PM) are present at much higher concentrations (ppm or vol% levels as opposed to ppb) at the inlet of their

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[32] Organic Atmospheric Pollutants: Polycyclic Hydrocarbons from Coal Atmospheric Fluidised Bed Combustion (AFBC), A.M Mastral, M.S. Callen, R. Murillo, and T. Garcia, Instituto de Carboquimica, 1999.

[33] Surrogacy Testing in the MPCRF, Prepared for U.S. EPA by ARCADIS, March 30, 2011. See Docket ID Item No. EPA–HQ–OAR–2002–0058–3942.

respective controls devices (*e.g.,* SCR, wet scrubber, fabric filter or ESP).[34] Even mercury—which is a very low concentration pollutant that is not controlled by upstream combustion—is often present in concentrations of approximately 10 ppb at the inlet of the control devices and at a concentrations of approximately 1 ppb at the exit. Fixed-bed activated carbon adsorption units can be sized for controlling VOC-containing streams at concentrations *as low as several ppb* in the case of some toxic chemicals. However, while fixed-bed activated carbon adsorbers can be sized to treat low concentrations (several ppb) of VOC-containing gas streams, they can also introduce considerable pressure drop across the system resulting in additional electricity used by the system fans, which must be appropriately sized to overcome the pressure drop through the carbon beds. Therefore, we maintain that the quantity of organic HAPs being emitted below CO levels of 130 ppm is not susceptible to further control.

Furthermore, we disagree that all organic HAP emissions can be reduced with ACI and note that the commenter is citing a quote from an ACI vendor and not a statement from the EPA, as explained above. The effectiveness of ACI for air pollutant control is related to contact between a sorbent particle and a molecule of pollutant. The higher the concentration of the air pollutant—whether that be mercury or organic HAP—the more effective the pollutant is removed via adsorption to the carbon surface. As the concentration of the pollution decreases, the likelihood of contact between a pollutant molecule and a carbon sorbent particle declines significantly; and the effectiveness is diminished. Similar to the results that were observed for mercury, low inlet concentrations of organic HAP will result in a similar impact on control efficiency using ACI. In fact, none of the best performing organic HAP units are using ACI because those units are more effectively reducing organic HAP through combustion. It also is important to note that combustion devices, such as boilers, are among the best controls available for reducing organic HAP from various industrial processes.

F. New Source Definition

Several commenters requested that the EPA revise its definition of ‘‘new source’’ to base the determination of which sources must meet revised new source standards to only those sources that constructed or reconstructed after the EPA's 2020 proposed action for this final rule. The EPA disagrees that this is compelled by the statutory language and believes this final rule reflects a reasonable approach in these particular circumstances.

One commenter refers to the EPA's part 63 General Provisions regulations, which state that ‘‘[a] new affected source for which construction commences after proposal of a relevant standard is subject to relevant standards for new affected sources, including compliance dates.’’ 40 CFR 63.5(b)(1). The EPA disagrees that the statutory and regulatory provisions the commenter refers to are relevant here, or that those provisions override the statutory definition of ‘‘new source,’’ which is expressly based on the date EPA ‘‘first proposes’’ an emissions standard that applies to the source. See also 40 CFR 63.2 (defining ‘‘new source’’ in same manner). In fact, the different definition of ‘‘new source’’ in section 111 to which the commenter also refers only underscores the fact that Congress specifically defined ‘‘new source’’ in section 112 to be based on the ‘‘first’’ proposal of an emissions standard, rather than the more general ‘‘proposed regulations’’ found in section 111. Similarly, the other provisions the commenter refers to are not dispositive here. First, the General Provisions regulations the commenter refers to address pre-construction review requirements (40 CFR 63.5) and define ‘‘emissions standard’’ to mean ‘‘a national standard, limitation, prohibition, or other regulation’’ issued under section 112 (40 CFR 63.2). Neither of these provisions addresses the question here—whether the EPA must always re-define new sources when it revises a MACT standard. Similarly, the statutory definition of ‘‘emission standard’’ contains nothing that addresses whether the definition of ‘‘new source’’ under section 112 changes every time the EPA proposes to revise a MACT standard (CAA section 302(k)).

The EPA agrees that section 112(i)(2) does not address the commenter's request. That provision allows for a longer compliance period for new sources where the EPA's proposed standards are less stringent than the standards in the final rule. The commenter further claims that Congress did not address a situation where the EPA proposes to revise an emissions standard ten years after its first proposal of standards, and notes that this time period is even longer than the periodic review timeframe of 8 years. The commenter also claims that the EPA did not establish the definition of ‘‘new source’’ based on the arguably ‘‘first’’ proposal of MACT standards in 2003, and that the Agency has therefore conceded that ‘‘first proposes’’ can mean a subsequent proposal. The EPA believes its approach in the final rule is a reasonable application of the definition of ‘‘new source’’ in this particular circumstance. The MACT standards promulgated in 2004 were vacated by the D.C. Circuit in an opinion in which the court stated that it expected the reissued standards to change significantly based on a fundamental error the EPA made in defining which sources were subject to section 112 emissions standards and which sources were subject to section 129 emissions standards. *NRDC* v. *EPA,* 489 F.3d 1250 (D.C. Cir. 2007). Since the vacatur voided the standards entirely, and restored the status quo ante, there was arguably no proposal remaining after the vacatur. In response to the *NRDC* decision, the EPA undertook an entirely new rulemaking to replace the vacated standards, including an extensive data collection effort and, importantly, a new MACT floor calculation methodology. 76 FR 15608. In that circumstance, it is reasonable to consider the EPA as having ‘‘first proposed’’ an emission standard applicable to these sources in the replacement rulemaking.[35] Here, in contrast, the *U.S. Sugar* court upheld the UPL methodology the EPA used to set the MACT floor standards in another part of its opinion.[36] Where the EPA is undertaking an entirely new process to establish ‘‘an emission standard’’ applicable to a source, it is reasonable to interpret the definition of ‘‘new source’’ as applying based on the date when the EPA ‘‘first proposes’’ that new standard. However, where the Agency is simply recalculating emissions standards based on the same data and

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[34] U.S. EPA. EPA Air Pollution Control Cost Manual. Sixth Edition. January 2002. EPA/452/B–02–001.

[35] The EPA notes that no commenter raised this issue in the 2011 rulemaking which was issued to replace the vacated 2004 standards, and it was not addressed in the record for the rule.

[36] As part of its review of standards affected by *U.S. Sugar,* the EPA also considered the court's prior decision in *NACWA* v. *EPA,* where the court remanded EPA's UPL methodology for further explanation based in part of the ‘‘anomalous result’’ the court found based on the UPL calculation for certain new source standards at a level that was less stringent than the UPL calculation for existing source standards. The EPA's subsequent explanation of the UPL methodology was upheld in *U.S. Sugar,* and it is appropriate for the Agency to consider standards where that ‘‘anomalous result’’ occurred and correct the calculation in those circumstances. For the new source solid fuel HCl standard, the EPA has done that through the application of its UPL methodology as applied to small data sets. The EPA's ‘‘small data sets’’ UPL approach was upheld by the D.C. Circuit in *Sierra Club* v. *EPA,* 895 F.3d 1 (2018).

same methodology, it is reasonable to treat the prior standard as EPA's ''first proposal'' of ''an emission standard'' for those sources.

One commenter claims that the EPA's proposed revised HCl standard for new source solid fuel units is significantly more stringent than the standard vacated by the *U.S. Sugar* court, and the significant change in stringency demonstrates that the EPA is using a new methodology which represents a ''drastic new approach'' that sources which constructed or reconstructed after the 2010 proposal could not have foreseen. Contrary to the commenter's assertion, the EPA is not applying a new methodology to revise the standards in this action. Rather, the EPA is simply correcting the error the court identified in how the Agency selected the best performing sources for each subcategory affected by the decision. It is not collecting any additional information or undertaking a wholesale revision of the standards. The fact that one standard became significantly more stringent does not mean the EPA has revised its methodology—it has not. Both the previous standard and the new standard were calculated using the UPL methodology.[37] Moreover, in its grant of rehearing on remedy, the court explained that it was remanding rather than vacating the standards affected by its holding because vacating the standards would remove important environmental protections while the EPA reissued the standards. *U.S. Sugar Corp.* v. *EPA,* 844 F.3d 268 (2016). It would be contrary to the court's purpose in revising its remedy to remand, rather than vacate, the emissions standards for the EPA to use the fact that its original standards were found to be inconsistent with the Act as a way to allow sources to meet less stringent standards.

Some commenters also pointed to other EPA rulemakings under sections 112 and 129 and requested that EPA take the approaches in those actions rather than the proposed approach. The EPA is basing its decision in this action on the facts and circumstances of this rulemaking, consistent with relevant provisions of CAA section 112. In the other actions that the commenters refer to, the circumstances were different and warranted a different approach. For example, the revision of EPA's Hospital/Medical/Infectious Waste Incinerator (HMIWI) standards in 2009 involved the collection of additional emissions information and a wholesale revision of the standards, unlike this action.[38] Further, actions taken to adopt MACT standards in the context of the EPA's risk and technology reviews under sections 112(d)(6) and (f)(2) also generally involve the calculation of new standards based on information that was not previously used in MACT calculations.

Commenters also express concern that the cost of compliance with the revised new source HCl standard for solid fuel units could be significant. One commenter refers to a specific unit constructed in 2016 which the commenter claims will need to add controls in order to meet the revised new source solid fuel HCl standard. The commenter claims that this renders the revised standard a ''beyond-the-floor'' MACT standard, and the EPA must therefore consider costs before adopting the revised standard. The EPA disagrees. The commenter conflates the two-step MACT standard-setting process in section 112(d)(2) and (d)(3). Under section 112(d)(3), the EPA's MACT standard can be no less stringent than the average emissions limitation achieved by the best performing twelve percent of sources in the subcategory, for existing sources, and the emissions limitation achieved by the best performing similar source, for new sources. It is well-established that, in setting these MACT floor standards, the EPA cannot consider the cost of achieving reductions. *National Lime Ass'n.* v. *EPA,* 233 F.3d 625 (D.C. Cir. 2000) (minimum stringency MACT floor requirements apply without regard to costs). This action addresses the D.C. Circuit's remand of certain MACT floor standards, and it is those floor standards that EPA is recalculating in a manner that is consistent with the court's decision. The fact that one particular recalculated standard may require sources to incur costs to comply does not transform the standard into a ''beyond-the-floor'' standard, and to do so would ignore the statute's clear directive establishing a minimum level of emissions reductions below which the MACT standard cannot be set, regardless of cost. Moreover, virtually all sources constructed or reconstructed after the 2010 proposal are in fact meeting the revised HCl standard and will therefore not incur any compliance costs.

Finally, contrary to commenters' assertions, the EPA is not applying a new standard retroactively. Every source affected by these revised limits has 3 years to come into compliance with the revised standards following promulgation, regardless of construction date. The commenter does not explain how the revised standard is a retroactive standard, except to state that a source that was constructed in 2016 could not have foreseen that the EPA would subsequently revise standards to make them more stringent. Section 112(a) defines ''new source'' based on when EPA ''first proposes'' an emissions standard for a source, and, as explained above, in this particular circumstance it is reasonable to consider EPA's 2010 proposal as the date when the Agency ''first proposed'' an emissions standard for these sources. In addition, the EPA is revising the standards to respond to the D.C. Circuit's remand in U.S. Sugar, and it was reasonable to assume, once that remand was issued, that revised standards would in some cases be more stringent than the remanded standards.

G. Approval for CO_2 in Lieu of O_2 Monitoring for CO CEMS Compliance Calculations

The current version of this regulation contains language which details how facilities that seek to monitor CO_2 in lieu of oxygen as part of their CEMS used to demonstrate compliance with the CO emission limits in this subpart must have this approach approved as an alternative method before doing so. In the proposed rule, we took comment on replacing the requirement to have approval of an alternative test method with a required methodology to be followed when monitoring CO_2 in lieu of oxygen as the diluent for CO which would account for any changes in CO_2 emission levels caused by a control device, etc. We further proposed removing several requirements for the continuous monitoring of moisture and flow which we found to be unnecessary.

Commenters supported the proposal to modify the requirement to obtain the Administrator's approval and allow this change to become self-implementing. Commenters further agreed with the EPA's proposal to remove requirements for the continuous monitoring of moisture and flow which were found to be unnecessary.

We are finalizing these provisions as proposed. Some commenters requested that we remove the requirements for continuous monitoring of moisture and flow when CO_2 measurements do not require these values for compliance

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[37] The commenter claims that the solid fuel HCl standard for new sources was not vacated by the *U.S. Sugar* court and therefore EPA is not revising the standard based on that decision, but for other reasons. However, as noted above, as part of its review of standards affected by the *U.S. Sugar* remand on this issue, the EPA also applied its ''small data sets'' UPL memorandum where appropriate.

[38] The EPA notes that the definition of ''new solid waste incineration unit'' in section 129(g)(2), which was adopted in the 1990 CAAA, does not contain any reference to EPA's ''first'' proposal of applicable standards.

calculations. We believe the revisions accommodate the removal of moisture and flow when a dry CO_2 analyzer is used, obviating the need to make any additional changes to the rule language.

IV. Results and Final Decisions

A. What are the resulting changes to emission limits?

Based on all of the revisions made to address the remand related to ranking and assessing co-fired units in the MACT floor calculations, the changes made for UPL calculations for small datasets, the decisions to propose certain limits as beyond-the-floor limits, and consideration of public comments, we are finalizing revisions to 34 different emission limits. The detailed list of revisions to unit rankings and revised MACT floor calculations are presented in the docketed memorandums, *Revised MACT Floor Analysis (2019) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source* and *Revised MACT Floor Analysis (2021) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source.* Of these 34 emission limits, 28 of the limits are more stringent than the corresponding limits in the 2013 final rule. Six of the limits are modestly less stringent, with no more than a 25-percent change from the corresponding limit in the 2013 final rule. The final limits are shown in Table 4, along with corresponding limits from the 2013 final rule.

TABLE 4—SUMMARY OF CHANGES TO EMISSION LIMITS IN THE FINAL ACTION

Subcategory	Pollutant	2013 final rule emission limit (lb/MMBtu of heat input or ppm at 3-percent oxygen for CO)	Revised emission limit (lb/MMBtu of heat input or ppm at 3-percent oxygen for CO)
New—Solid	HCl	2.2E–02	2.1E–04
New—Dry Biomass Stoker	TSM	4.0E–03	5.0E–03
New—Biomass Fluidized Bed	CO	230	130
New—Biomass Fluidized Bed	PM	9.8E–03	4.1E–03
	(TSM)	(8.3E–05)	(8.4E–06)
New—Biomass Suspension Burner	CO	2,400	220
New—Biomass Suspension Burner	TSM	6.5E–03	8.0E–03
New—Biomass Hybrid Suspension Grate	CO	1,100	180
New—Biomass Dutch Oven/Pile Burner	PM	3.2E–03	2.5E–03
New—Biomass Fuel Cell	PM	2.0E–02	1.1E–02
New—Wet Biomass Stoker	CO	620	590
New—Wet Biomass Stoker	PM	0.03	0.013
New—Liquid	HCl	4.4E–04	1.5E–04
New—Heavy Liquid	PM	1.3E–02	1.9E–03
	(TSM)	(7.5E–05)	(6.4E–06)
New—Process Gas	PM	6.7E–03	7.3E–03
Existing—Solid	HCl	2.2E–02	2.0E–02
Existing—Solid	Hg	5.7E–06	5.4E–06
Existing—Coal	PM	4.0E–02	3.9E–02
Existing—Coal Stoker	CO	160	150
Existing—Dry Biomass Stoker	TSM	4.0E–03	5.0E–03
Existing—Wet Biomass Stoker	CO	1,500	1,100
Existing—Wet Biomass Stoker	PM	3.7E–02	3.4E–02
	(TSM)	(2.4E–04)	(2.0E–04)
Existing—Biomass Fluidized Bed	CO	470	210
Existing—Biomass Fluidized Bed	PM	1.1E–01	7.4E–03
	(TSM)	(1.2E–03)	(6.4E–05)
Existing—Biomass Suspension Burners	PM	5.1E–02	4.1E–02
	(TSM)	(6.5E–03)	(8.0E–03)
Existing—Biomass Dutch Oven/Pile Burner	PM	2.8E–01	1.8E–01
Existing—Liquid	Hg	2.0E–06	7.3E–07
Existing—Heavy Liquid	PM	6.2E–02	5.9E–02
Existing—Non-Continental Liquid	PM	2.7E–01	2.2E–01
Existing—Process Gas	PM	6.7E–03	7.3E–03

B. What compliance dates are we finalizing?

We are finalizing that facilities have up to 3 years after the effective date of the final rule to comply with the revised emissions limits in this final rule. Before this date, facilities must continue to comply with the rule as it was finalized in 2015. This allowance is being made considering that some facilities may require additional add-on controls or monitoring equipment to be designed, purchased, and installed in order to meet the more stringent emission limits, or to modify the method of compliance based on the changes in emission limits. In addition, units will require lead time to prepare and execute their testing plans to demonstrate compliance with the revised emission limits and to update reports to incorporate the revised emission limits.

C. What other actions are we finalizing?

We proposed a number of technical corrections to correct inadvertent errors that were promulgated in the 2013 and 2015 final rules. Public commenters also noted several additional technical corrections to correct additional errors in the final rule. In addition, we are removing the references to the date of future final performance specifications for HCl CEMS because PS 18, the Performance Specifications for Gaseous Hydrogen Chloride, and Procedure 6, the Quality Assurance Requirements for Gaseous Hydrogen Chloride (HCl) Continuous Emission Monitoring Systems Used for Compliance Determination at Stationary Sources, were promulgated on July 7, 2017 at 80 FR 38628. The technical corrections we are finalizing are summarized in Table 5.

TABLE 5—FINALIZED TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART DDDDD

Section of subpart DDDDD	Description of correction
40 CFR 63.7500(a)	Revise this paragraph to remove the comma after "paragraphs (b)."
40 CFR 63.7521(c)(1)(ii)	Revise this paragraph to remove the requirement to collect samples during the test period at 1-hour intervals.
40 CFR 63.7525(l) and 40 CFR 63.7540(a)(15).	Remove the references to a date of a final performance specification for HCl CEMS.
40 CFR 63.7530(b)(4)(iii)	Revise this paragraph to remove the sentence regarding establishing the pH operating limit because establishing the pH operating limit is not required for a PM wet scrubber.
40 CFR 63.7540(a)(9)	Revise this paragraph to clarify that "certify" is intended to apply only to PM CEMS, not PM continuous parameter monitoring systems (CPMS) because PM CPMS do not have a performance specification.
40 CFR 63.7575	Revise the definition of "Other gas 1 fuel" to clarify that it is the maximum Hg concentration of 40 micrograms/cubic meter of gas.
	Add definition of "12-month rolling average" to clarify that the previous 12 months must be consecutive but not necessarily continuous.
	Revise paragraph (4) of definition "Steam output" to correct "heaters" to "headers."
Table 1	Revise the output limit in item 8.a to correct for a rounding error, the value is now 4.3E–01 lb per MMBtu instead of 4.2E–01 lb per MMBtu.
	Remove footnote "a" from item 12b for the TSM limit for fuel cell units designed to burn biomass/bio-based solids.
	Add footnote "a" to item 1a for the solid fuel HCl limit, item 14a for the liquid fuel HCl limit, and item 15b for the light liquid fuel TSM limit.
Table 2	Removed footnote "a" for item 14b for the liquid fuel mercury emission limit and 16b for light liquid PM emission limit.
Table 7	Revise footnote "b" to clarify that when multiple performance tests are conducted, the maximum operating load is the lower of the maximum values established during the performance tests.
Table 8	Revise item 8.d to clarify that the correct equations to use are Equations 15 and Equations 16, 17, and/or 18 in 40 CFR 63.7530.
Table 14	Remove footnote "a" from item 12b for the TSM limit for fuel cell units designed to burn biomass/bio-based solids.
	Add footnote "a" to item 15b for the light liquid fuel TSM limit.
Table 15	Removed footnote "a" for item 14b for the liquid fuel mercury emission limit and 16b for light liquid PM emission limit.

V. Summary of Cost, Environmental, and Economic Impacts

A. What are the affected sources?

According to CEDRI data through December 31, 2020, there are 577 boilers and process heaters, of which 485 remain operational and belong in one of the subcategories that are subject to numeric emission limits.[39] This count excludes any boilers that are no longer operational, boilers that have refueled and switched to the natural gas subcategory and are, therefore, no longer impacted by changes to emission limits, or boilers that are classified as small or limited use. Of these units, we estimate that 54 units (individual boilers or process heaters) will incur cost or emissions impacts due to these final amendments. In addition, the EPA estimates that an additional six biomass boilers or process heaters will be constructed and subject to the revised emission limits over the next 8 years.

B. What are the air quality impacts?

Table 6 of this preamble shows the incremental emissions reductions that we estimate these final amendments will achieve. The reductions are incremental to the reductions accounted for in the 2013 final rule. Nationwide emissions of selected HAP (*i.e.,* HCl, hydrogen fluoride, Hg, and metals) would be reduced by an additional 117 tpy as compared to the estimates in the 2013 final rule. This increase is due mainly to changes to certain emission limits that are anticipated to achieve additional reductions. We estimate the final amendments will result in an additional 110 tpy of reductions in HCl emissions. We estimate that the final amendments will have a modest effect on Hg, with an estimated additional reduction of 7.5 lbs per year. Emissions of filterable PM are estimated to decrease by 586 tpy, of which 446 tpy is $PM_{2.5}$, due to this final action. Emissions of non-Hg metals (*i.e.,* arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium) are estimated to decrease by 4.1 tpy. Estimates of reductions in antimony and cobalt were not quantified and are expected to be small. In addition, the final amendments are estimated to result in 1,141 tpy of reductions in SO_2 emissions. A discussion of the methodology used to estimate emissions, emissions reductions, and incremental emission reductions is presented in the memorandum, *Revised (2021) Methodology for Estimating Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants,* which is available in the docket for this action.

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[39] EPA notes that it considered compliance information from CEDRI for the purpose of evaluating costs and impacts of this action, in order to ensure that the actual costs of compliance are accurately reflected. For the reasons explained elsewhere, the Agency did not consider emissions data in CEDRI to recalculate the MACT floor standards affected by the D.C. Circuit remand in *U.S. Sugar.* The MACT "floor" is the minimum control level allowed for MACT standards promulgated under CAA section 112(d)(3) and may not be based on cost considerations.

TABLE 6—SUMMARY OF TOTAL EMISSIONS REDUCTIONS FOR THE FINAL RULE

[Tons per year]

Source	Subcategory	HCl	PM	Non-Hg metals [1]	Hg
Exiting Units	Coal	44.1	54.4	0.12	2.12E–03
	Biomass	13.6	521	3.8	1.65E–03
New Units	Biomass	52.3	9.9	0.14	0

[1] Arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium.

C. What are the cost impacts?

We estimated the total capital costs of the final amendments to be about $201 million and the total annualized costs to be about $49.6 million in 2016 dollars. The total capital and annual costs include costs for control devices, testing, and monitoring associated with the changes to the emission limits. These costs are incremental to the costs presented in the 2013 final rule in the sense that they show where units with compliance data must install add-on controls or modify compliance strategies in order to meet the more stringent limits in this final action. Table 7 shows the total capital and annual cost impacts of the final rule for each subcategory. The cost methodology and results are documented in the memorandum, *Revised (2021) Methodology for Estimating Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants,* which is available in the docket for this action.

TABLE 7—SUMMARY OF TOTAL CAPITAL AND ANNUAL COSTS FOR AFFECTED NEW AND EXISTING SOURCES FOR THE FINAL RULE

Source	Subcategory	Estimated number of affected units incurring a cost	Capital costs (millions 2016$)	Testing and monitoring annualized costs (millions 2016$/yr)	Annualized cost (millions 2016$/yr)
Existing Units	Coal	5	8.0	0.057	2.1
	Biomass	33	149.5	0.511	35.1
New Units	Biomass	11	43.3	0.043	12.3

Another way to present compliance costs is the present value (PV). A PV is an estimate of costs that is a discounted stream of the annualized costs for the final action calculated for the present day. The PV in 2016 of the costs is $265 million at a discount rate of 7 percent and $315 million at a discount rate of 3 percent. Calculated as an EAV, which is consistent with the PV of costs in 2016, the costs are $44 million at a discount rate of 7 percent and $45 million at a discount rate of 3 percent. These estimates are also in 2016 dollars. More information on the PV and EAV estimates can be found in the RIA for this final action which is available in the docket.

D. What are the secondary impacts?

The EPA estimated the additional water usage that would result from installing wet scrubbers to meet the amended emission limits for HCl would be 0.75 million gallons per year for new and existing sources compared to the 2013 baseline. In addition to the increased water usage, an additional 0.29 million gallons per year of wastewater will be produced for new and existing sources. The annual costs of treating the additional wastewater are approximately $1,920. These additional costs are accounted for in the control cost estimates.

The EPA estimated the additional solid waste that would result due to the final amendments to be 1,540 tpy for new and existing sources. Solid waste is generated from flyash and dust captured in fabric filters and electrostatic precipitators (ESP) installed for PM and Hg controls as well as from spent materials from wet scrubbers and sorbent injection systems installed for additional HCl controls. The costs of handling the additional solid waste generated are approximately $73,900. These costs are also accounted for in the control costs estimates.

The EPA estimated the final amendments would result in an increase of about 74.4 million kilowatts per year in national energy usage from the electricity required to operate control devices, such as wet scrubbers, ESPs, and fabric filters which are expected to be installed to meet the revised emission limits. This energy requirement is estimated to result in an increase of approximately 32,910 tpy CO_2 based on emissions related to additional energy consumption.

A discussion of the methodology used to estimate impacts is presented in the *Revised (2021) Methodology for Estimating Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants,* which is available in the docket for this action.

E. What are the economic impacts?

The EPA conducted an economic impact analysis for this final rule, as detailed in the *Regulatory Impact Analysis for the ICI Boilers NESHAP Final Amendments,* which is available in the docket for this action. The economic impacts are calculated as the percentage of total annualized costs incurred by affected parent owners to their annual revenues. This ratio of total annualized costs to annual revenues provides a measure of the direct economic impact to parent owners of affected facilities while presuming no passthrough of costs to consumers of output produced by these facilities. Of 30 parent owners affected by this final rule, two of them will incur total annualized costs of 1 percent or greater of their revenues. The median total annualized cost of sales for affected parent owners is less than 0.01 percent. While two parent owners may experience substantial economic impacts as a result of complying with this final rule, neither one is a small business according to Small Business Administration (SBA) guidelines. Overall, based on these estimated impacts, we can conclude that the economic impacts are relatively low for the affected entities and the multiple affected industries, and consumers of affected output should experience relatively low price changes.

F. What are the benefits?

There are no monetized benefits from the HAP emissions reductions directly regulated under this action due to lack of necessary input data. However, the EPA reports the estimated impact on health benefits from changes in PM$_{2.5}$ and SO$_2$ emissions that occur as a result of this final rule. The estimated health benefits are the monetized value of the human health benefits among populations exposed to changes in PM$_{2.5}$. This rule is expected to alter the emissions of PM$_{2.5}$ (and SO$_2$). Due to the small change in emissions expected, we used the ''benefit per ton'' (BPT) approach to estimate the benefits of this rulemaking. The EPA has applied this approach in several previous RIAs[40] in which the economic value of human health impacts is derived at the national level based on previously established source-receptor relationships from photochemical air quality modeling.[41] These BPT estimates provide the total monetized human health benefits (the sum of PM-attributable premature deaths and premature morbidity) of reducing 1 ton of PM$_{2.5}$ (or PM$_{2.5}$ precursor such as SO$_2$) from a specified source. Since proposal of this rule, the EPA has updated its BPT estimates to include state level estimates specifically for the Industrial Boiler sector. The method used to derive these estimates is described in the *Technical Support Document on Estimating the Benefit per Ton of Reducing Directly-Emitted PM$_{2.5,}$ PM$_{2.5}$ Precursors and Ozone Precursors from 21 Sectors and its precursors from 21 sectors.*[42] One limitation of using the BPT approach is an inability to provide estimates of the health benefits associated with exposure to HAP (HCl, for example), CO, or nitrogen dioxide. The photochemical modeled emissions of the industrial point source sector-attributable PM$_{2.5}$ concentrations used to derive the BPT values may not match the change in air quality resulting from the emissions controls.

Specifically, all national-average BPT estimates reflect the geographic distribution of the modeled emissions, which may not exactly match the emission reductions that would occur due to rulemaking, and they may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location. The new BPT estimates developed for the Industrial Boiler sector in 2021 developed state-level estimates that addressed some of the limitations of the national analysis. Given the use of state level, sector specific air quality modeling and the small changes in emissions considered in this rulemaking, the difference in the quantified health benefits that result from the BPT approach compared with those obtained using a full-form air quality model should be minimal.

Table 8 summarizes the monetized PM related health benefits per ton in the states where units with emission reductions are located, using discount rates of 3 percent and 7 percent. Table 9 summarizes the monetized SO$_2$-related health benefits per ton of reducing precursor pollutant emissions in the states where units with emission reductions are located, using discount rates of 3 and 7 percent.

TABLE 8—ESTIMATED PM$_{2.5}$-RELATED BENEFITS PER TON OF FINAL RULE

State	Benefit per ton low (3% discount rate)	Benefit per ton low (7% discount rate)	Benefit per ton high (3% discount rate)	Benefit per ton high (7% discount rate)
CA	$503,000	$452,000	$510,000	$459,000
FL	140,000	126,000	141,000	127,000
GA	151,000	136,000	156,000	141,000
LA	117,000	105,000	123,000	110,000
ME	48,200	43,400	50,500	45,500
MI	259,000	233,000	262,000	236,000
NC	171,000	154,000	173,000	156,000
OK	103,000	92,600	106,000	95,8000
TN	227,000	204,000	235,000	212,000
WI	148,000	133,000	156,000	140,000

TABLE 9—ESTIMATED SO$_2$-RELATED BENEFITS PER TON OF FINAL RULE

State	Benefit per ton low (3% discount rate)	Benefit per ton low (7% discount rate)	Benefit per ton high (3% discount rate)	Benefit per ton high (7% discount rate)
AL	$50,600	$45,500	$52,100	$46,900
AR	42,300	38,100	43,000	38,700
FL	45,600	41,000	46,400	41,800
IL	54,800	49,300	55,300	51,300
MI	56,000	50,300	57,000	49,800

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[40] U.S. EPA. Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States. June 2011; Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, December 2011; and Regulatory Impact Analysis for the Particulate Matter National Ambient Air Quality Standards; December 2012.

[41] Fann N, Fulcher CM, Hubbell BJ. The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution. Air Qual Atmos Health. 2009;2(3):169–176. doi:10.1007/s11869–009–0044–0.

[42] U.S. EPA. 2021. Technical Support Document (BPT TSD) on Estimating the Benefit per Ton of Reducing Directly-Emitted PM$_{2.5,}$ PM$_{2.5}$ Precursors and Ozone Precursors from 21 Sectors and its precursors from 21 sectors. Technical Support Document. Available at: *https://www.epa.gov/benmap/reduced-form-tools-calculating-pm25-benefits.*

TABLE 9—ESTIMATED SO_2-RELATED BENEFITS PER TON OF FINAL RULE—Continued

State	Benefit per ton low (3% discount rate)	Benefit per ton low (7% discount rate)	Benefit per ton high (3% discount rate)	Benefit per ton high (7% discount rate)
NC	45,300	40,700	45,600	41,000
TX	14,900	13,400	15,100	13,600
VA	53,400	48,100	54,100	48,700
WA	20,300	18,300	20,800	18,700

TABLE 10—ANNUAL EMISSIONS REDUCTIONS OF $PM_{2.5}$ AND SO_2 BY STATE

State	Emission reductions (tons)	
	$PM_{2.5}$	SO_2
AL		26
AR		<0.1
CA	33	
FL	17	557
GA	10	
IL		306
LA	27	
ME	5	
MI	4	41
NC	2	179
OK	257	
TN	40	
TX		1
VA		31
WA		2
WI	51	

Table 10 above provides the annual emissions reductions of $PM_{2.5}$ and SO_2 by state. Table 11 summarizes the range of estimated benefits of these annual emission reductions by pollutant for the two benefit per ton estimates at discount rates of 3 percent and 7 percent.

TABLE 11—ESTIMATED $PM_{2.5}$ AND SO_2-RELATED ANNUAL HEALTH BENEFITS OF FINAL RULE

[Millions of 2016$]

Pollutant	Benefits low (3% discount rate)	Benefits low (7% discount rate)	Benefits high (3% discount rate)	Benefits high (7% discount rate)
$PM_{2.5}$	$68	$62	$68	$62
SO_2	55	50	56	51
Total	123	112	124	113

There are also climate disbenefits from the increase in CO_2 emissions that result from the increase in national energy use from control device operation. We estimate the social disbenefits of CO_2 emission increases expected from this final rule using the SC–CO_2 estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990.*[43] We have evaluated the SC–CO_2 estimates in the February 2021 TSD and have determined that these estimates are appropriate for use in estimating the social value of CO_2 emission changes expected from this final rule as part of fulfilling analytical guidance with respect to E.O. 12866. These SC–CO_2 estimates are interim values developed for use in benefit-cost analyses until an improved estimate of the impacts of climate change can be developed based on the best available science and economics.

Table 12 shows the estimated monetary value of the estimated changes in CO_2 emissions expected to occur for the final rule. For 2022–2024, no changes in CO_2 emissions occur since the control technologies included in the cost analysis mentioned in the Cost Methodology memo for the final rule are not expected to begin operation until 3 years after the effective date of the final rule, or 2025. Hence, there are no climate disbenefits for these 3 years. In 2025, the EPA estimated the dollar value of the CO_2-related effects by applying the SC–CO_2 estimates, included in the RIA's benefits chapter, to the estimated changes in CO_2

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[43] Interagency Working Group on Social Cost of Greenhouse Gases (IWG). 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. February. United States Government. Available at: *https://www.whitehouse.gov/briefing-room/blog/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution/.*

emissions in the corresponding year under the final rule.[44] The EPA calculated the present value and annualized benefits from the perspective of 2020 by discounting each year-specific value to the year 2020 using the same discount rate used to calculate the SC–CO_2.[45]

TABLE 12—ESTIMATED CLIMATE DISBENEFITS FROM CHANGES IN CO_2 EMISSIONS FOR 2025

[Millions of 2016$] [a]

	Discount rate and statistic				
	Year	5% average	3% average	2.5% average	3% 95th percentile
Final Rule	2025	0.5	1.7	2.5	5.2

[a] Climate disbenefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC–CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). We emphasize the importance and value of considering the disbenefits calculated using all four SC–CO_2 estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

The climate disbenefits associated with the additional 32,910 short tons (or 29,855 metric tons) per year of CO_2 emissions generated as a result of the requirements of this final rule are therefore $1.7 million at a 3 percent discount rate, and range from $0.5 million at a 2.5 percent discount rate to $5.2 million at a 3 percent discount rate (95th percentile), all in 2016 dollars.[46] These disbenefits are estimated for 2025, the year of full implementation of this final rule (3 years after the effective date) using the interim social cost of carbon (SC–CO_2) for 2025 as shown in Table 12 to be consistent with the year for the $PM_{2.5}$ and SO_2 BPTs applied to generate those monetized benefits presented earlier in section V.F.[47]

These disbenefits are included in the estimates of benefits and net benefits for this final rule. The benefit analysis for this final rule, which includes PV and EAV estimates for the benefits and net benefits, is detailed in the *Regulatory Impact Analysis for the ICI Boilers and Process Heaters NESHAP Final Amendments,* which is available in the docket for this action.

G. What analysis of environmental justice did we conduct?

Executive Order 12898 directs the EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms; specifically, minority populations, low-income populations, and indigenous peoples (59 FR 7629, February 16, 1994). Additionally, Executive Order 13985 was signed to advance racial equity and support underserved communities through Federal government actions (86 FR 7009, January 20, 2021). The EPA defines environmental justice (EJ) as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA further defines the term fair treatment to mean that ''no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies'' (*https://www.epa.gov/environmentaljustice*). In recognizing that minority and low-income

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[44] CO_2 emissions increases above the baseline as a result of the modeled policy are first expected in 2025, as control technologies applied in response to the final rule first begin operation in that year, and those emissions increase remain at that level afterwards, according to the cost analysis for this rule.

[45] According to OMB's Circular A–4, an ''analysis should focus on benefits and costs that accrue to citizens and residents of the United States'', and international effects should be reported separately. Circular A–4 also reminds analysts that ''[d]ifferent regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues.'' To correctly assess the total climate damages to U.S. citizens and residents, an analysis must account for all the ways climate impacts affect the welfare of U.S. citizens and residents, how U.S. GHG mitigation activities affect mitigation activities by other countries, and spillover effects from climate action elsewhere. The SC–CO_2 estimates used in regulatory analysis under revoked E.O. 13783, including in the RIA for the proposed rule, were an approximation of some of the U.S.-specific climate damages from GHG emissions (*e.g.,* $7/mt$CO_2$ (2016 dollars) using a 3% discount rate for emissions occurring in 2025). Applying the same estimate (based on a 3% discount rate) to the CO_2 emissions expected under the final rule would yield disbenefits from climate impacts of $0.2 million (2016 dollars) in 2025. However, as discussed at length in the February 2021 TSD, these estimates are an underestimate of the damages of CO_2 emissions accruing to U.S. citizens and residents, as well as being subject to a considerable degree of uncertainty due to the manner in which they are derived. In particular, the estimates developed under revoked E.O. 13783 did not capture significant regional interactions, spillovers, and other effects and so are incomplete underestimates. As the U.S. Government Accountability Office (GAO) concluded in a June 2020 report examining the SC–GHG estimates developed under E.O. 13783, the models ''were not premised or calibrated to provide estimates of the social cost of carbon based on domestic damages''. U.S. Government Accountability Office (GAO). 2020. Social Cost of Carbon: Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis. GAO–20–254. Further, the report noted that the National Academies found that country-specific social costs of carbon estimates were ''limited by existing methodologies, which focus primarily on global estimates and do not model all relevant interactions among regions''. It is also important to note that the SC–GHG estimates developed under E.O. 13783 were never peer reviewed, and when their use in a specific regulatory action was challenged, the U.S. District Court for the Northern District of California determined that use of those values had been ''soundly rejected by economists as improper and unsupported by science,'' and that the values themselves omitted key damages to U.S. citizens and residents including to supply chains, U.S. assets and companies, and geopolitical security. The Court found that by omitting such impacts, those estimates ''fail[ed] to consider . . . important aspect[s] of the problem'' and departed from the ''best science available'' as reflected in the global estimates. *California* v. *Bernhardt,* 472 F. Supp. 3d 573, 613–14 (N.D. Cal. 2020). The EPA continues to center attention in this regulatory analysis on the global measures of the SC–GHG as the appropriate estimates and as necessary for all countries to use to achieve an efficient allocation of resources for emissions reduction on a global basis, and so benefit the U.S. and its citizens.

[46] In order to calculate these values, it is necessary to convert tons (short) of emissions to metric tons. These values may be converted to $/short ton using the conversion factor 0.90718474 metric tons per short ton for application to the short ton CO_2 emissions impacts provided in this rulemaking. Hence, 32,910 short tons of emissions become 29,855 metric tons (tonnes) of emissions.

[47] These SC–CO_2 values are stated in $/metric ton CO_2 and rounded to the nearest dollar. Such a conversion does not change the underlying methodology, nor does it change the meaning of the SC–CO_2 estimates. For both metric and short tons denominated SC–CO_2 estimates, the estimates vary depending on the year of CO_2 emissions and are defined in real terms, *i.e.,* adjusted for inflation using the Gross Domestic Product (GDP) implicit price deflator.

populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

To examine the potential for any EJ issues that might be associated with the source category, we performed a demographic analysis, which is an assessment of individual demographic groups of the populations living within 5 kilometers (km) and within 50 km of facilities with affected sources.[48] The EPA then compared the data from this analysis to the national average for each of the demographic groups.

The results of the demographic analysis indicate that, for populations within 5 km of the facilities in the source category, the percent minority population (being the total population minus the white population) is smaller than the national average (36 percent versus 40 percent). Within minorities, the percent of the population that is African American, Other and Multiracial, and Native American are similar to the national averages. The percent of the population that is Hispanic or Latino is below the national average (14 percent versus 19 percent). The percent of people living below the poverty level was higher than the national average (18 percent versus 13 percent). The percent of people living in linguistic isolation was less than the national average. The results of the analysis of populations within 50 km of the facilities in the source category were similar to the 5 km analysis, with the exception of the percent of the population living below the poverty level and the percent of the population over 25 without a high school diploma, which were closer to the national averages.

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). Nationwide emissions of selected HAP (*i.e.,* HCl, hydrogen fluoride, Hg, and metals) would be reduced by an additional 117 tpy as compared to the estimates in the 2013 final rule. We estimate the final amendments will result in an additional 110 tpy of reductions in HCl emissions, and 7.5 lbs per year of Hg. Emissions of filterable PM are estimated to decrease by 586 tpy, of which 446 tpy is $PM_{2.5}$. Emissions of non-Hg metals (*i.e.,* arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium) are estimated to decrease by 4.1 tpy. In addition, the final amendments are estimated to result in 1,141 tpy of reductions in SO_2 emissions. A breakdown of emissions reductions by facility is presented in Appendix C of the memorandum, *Revised (2021) Methodology for Estimating Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants,* which is available in the docket for this action. This final rule increases the level of environmental protection for all affected populations, without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low-income, or indigenous populations.

A summary of the proximity demographic assessment performed for Industrial, Commercial, and Institutional Boilers and Process Heaters facilities is included as Table 13. The methodology and the results of the demographic analysis are presented in a technical report, *Analysis of Demographic Factors for Populations Living Near Industrial, Commercial, and Institutional Boilers and Process Heaters,* available in this docket for this action (Docket ID EPA–HQ–OAR–2002–0058).

TABLE 13—PROXIMITY DEMOGRAPHIC ASSESSMENT RESULTS

Demographic group	Nationwide	Population within 50 km of 40 facilities	Population within 5 km of 40 facilities
Total Population	328,016,242	14,889,295	635,825
	White and Minority by Percent		
White	60%	65%	64%
Minority	40%	35%	36%
	Minority by Percent		
African American	12%	14%	13%
Native American	0.7%	0.5%	0.8%
Hispanic or Latino (includes white and nonwhite)	19%	13%	14%
Other and Multiracial	8%	7%	8%
	Income by Percent		
Below Poverty Level	13%	14%	18%
Above Poverty Level	87%	86%	82%
	Education by Percent		
Over 25 and without a High School Diploma	12%	12%	14%
Over 25 and with a High School Diploma	88%	88%	86%
	Linguistically Isolated by Percent		

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[48] Note that many facilities have more than one affected boiler or process heater.

TABLE 13—PROXIMITY DEMOGRAPHIC ASSESSMENT RESULTS—Continued

Demographic group	Nationwide	Population within 50 km of 40 facilities	Population within 5 km of 40 facilities
Linguistically Isolated	5%	3%	4%

Notes:

- The nationwide population count and all demographic percentages are based on the Census' 2015–2019 American Community Survey five-year block group averages and include Puerto Rico. Demographic percentages based on different averages may differ. The total population counts within 5 km and 50 km of all facilities are based on the 2010 Decennial Census block populations.
- Minority population is the total population minus the white population.
- To avoid double counting, the "Hispanic or Latino" category is treated as a distinct demographic category for these analyses. A person is identified as one of five racial/ethnic categories above: White, African American, Native American, Other and Multiracial, or Hispanic/Latino. A person who identifies as Hispanic or Latino is counted as Hispanic/Latino for this analysis, regardless of what race this person may have also identified as in the Census.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.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 an economically significant regulatory action that was submitted to OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The RIA contains the estimated costs, benefits, and other impacts associated with this action, and it is available in the docket.

B. Paperwork Reduction Act (PRA)

The new information collection activities in this rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2028.12. OMB Control Number 2060–0551. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

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

The final amendments changed several emission limits as part of the EPA's response to the remand granted on December 23, 2016, by the D.C. Circuit. The changes resulted in more stringent emission limits in some cases, which is expected to require additional recordkeeping and reporting burden. This increase is a result of additional monitoring and control devices anticipated to be installed to comply with the more stringent emission limits in the amendments. With additional control devices, comes additional control device parametric monitoring, or in the case of CO, continuous emissions monitoring, and the associated records of that monitoring that must be maintained on-site and reported. Over the next 3 years, approximately 34 respondents operating existing large solid fuel-fired boilers and 5 respondents operating new solid fuel-fired boilers will be impacted by the new requirements under the standard as a result of these amendments. In addition to the costs to install and maintain records of additional monitoring equipment, the ICR details other additional recordkeeping and reporting burden changing records associated with adjusting operating parameter limit values, modifying monitoring plans, and familiarizing themselves with the changes in the final amendments.

Respondents/affected entities: Owners or operators of ICI boilers and process heaters.

Respondent's obligation to respond: Mandatory, 40 CFR part 63.

Estimated number of respondents: 39.

Frequency of response: Semi-annual, annual, periodic.

Total estimated burden: 1,553 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $1,130,000 (per year), includes $949,000 annualized capital or operation and maintenance costs.

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

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. Of the 30 entities (ultimate parent entities, all but two being in the private sector) determined to be impacted by this action, two are small entities. Of these two small entities, none is expected to incur any costs as a result of compliance with this action. More information on these small entity impacts is available in the RIA.

D. Unfunded Mandates Reform Act (UMRA)

This action contains a Federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, the EPA has prepared a written statement required under section 202 of UMRA. The statement is included in the RIA for this final rule that is in the docket for this action. This action is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

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.

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

This action does not have tribal implications as specified in Executive

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

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

This action is not subject to Executive Order 13045 because the EPA does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This action's health and risk assessments are contained in the RIA.

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. The energy impacts estimated for this action increased only slightly the energy impacts estimated for the March 21, 2011, final rule which was concluded not to be a significant regulatory action under Executive Order 13211. Therefore, we conclude that this final rule is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This action does not involve any new technical standards from those contained in the March 21, 2011, final rule. Therefore, the EPA did not consider the use of any voluntary consensus standards. See 76 FR 15660–15662 for the NTTAA discussion in the March 21, 2011, final rule. The EPA is, however, formalizing the incorporation of one technical standard that was already incorporated in 40 CFR 63.14 as well as in several existing tables in 40 CFR part 63, subpart DDDDD. This standard is ASTM D6784–02 (Reapproved 2008), Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method). This method, which describes the measurement of particle-bound, oxidized, elemental, and total mercury in stationary-source flue gases provides data that can be used for emissions assessments and reporting as well as the certification of continuous mercury monitoring systems. It describes equipment and procedures for obtaining samples of mercury from effluent ducts and stacks, for laboratory analysis, and for calculating results. It is applicable for sampling elemental, oxidized, and particle-bound mercury in flue gases of coal-fired stationary sources. It may not be suitable at all measurement locations, particularly those with high particulate loadings. Method applicability is limited to flue gas stream temperatures within the thermal stability range of the sampling probe and filter components. The standard is available to the public for free viewing online in the Reading Room section on ASTM's website at *https://www.astm.org/READINGLIBRARY/*. Hardcopies and printable versions are also available for purchase from ASTM. Additional information can be found at *https://www.astm.org/products-services/standards-and-publications.html*.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). The documentation for this decision is contained in a technical report, *Analysis of Demographic Factors for Populations Living Near Industrial, Commercial, and Institutional Boilers and Process Heaters,* available in this docket for this action (Docket ID EPA–HQ–OAR–2002–0058).

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a ''major rule'' as defined by U.S.C. 804(2).

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Incorporation by reference, Reporting and recordkeeping requirements.

Michael S. Regan,
Administrator.

For the reasons stated in the preamble, 40 CFR part 63 is amended as follows:

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

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

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

Subpart A—General Provisions

■ 2. Section 63.14 is amended by revising paragraph (h)(103) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(h) * * *

(103) ASTM D6784–02 (Reapproved 2008), Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), Approved April 1, 2008; IBR approved for §§ 63.2465(d); 63.11646(a); and 63.11647(a) and (d); and tables 1, 2, 5, 11, 12t, 13, 14, and 15 to subpart DDDDD; tables 4 and 5 to subpart JJJJJ; tables 4 and 6 to subpart KKKKK; table 5 to subpart UUUUU; appendix A to subpart UUUUU; and table 4 to subpart JJJJJJ.

* * * * *

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

■ 3. Section 63.7500 is amended by revising paragraphs (a) introductory text, (a)(1), (c), and (e) to read as follows:

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

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b) through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3 and 11 through 15 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 Table 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 Table 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 headers would calculate a total steam energy output using Equation 1 of § 63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Table 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 (iv) of this section, but on or after October 6, 2025, you must comply with the emission limits in Table 1 to this subpart. If you operate an existing boiler or process heater, you can choose to comply with alternative limits as discussed in paragraph (a)(1)(v) of this section, but on or after October 6, 2025 you must comply with the emission limits in Table 2 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 11 or 14 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 12 or 14 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 13 or 14 to this subpart until January 31, 2016.

(iv) If you operate a new boiler or process heater, you must comply with either the emission limits in Table 1 to this subpart or the emission limits in Table 14 to this subpart until you must comply with the emission limits in Table 1.

(v) If you operate an existing boiler or process heater, you must comply with either the emission limits in Table 2 to this subpart or the emission limits in Table 15 to this subpart until you must comply with the emission limits in Table 2.

* * * * *

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or Tables 11 through 15 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

* * * * *

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or Tables 11 through 15 to this subpart, or the operating limits in Table 4 to this subpart.

* * * * *

■ 4. Section 63.7505 is amended by revising paragraph (c) to read as follows:

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

* * * * *

(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 Table 1 or 2 or Tables 11 through 15 to this subpart.

* * * * *

■ 5. Section 63.7510 is amended by revising paragraphs (a) introductory text, (b), (c), (f), and (j) to 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 Table 1 or 2 or Tables 11 through 15 to this subpart through performance (stack) testing, your initial compliance requirements include all the following:

* * * * *

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraphs (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(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 Table 1 or 2 or Tables 11 through 15 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.

* * * * *

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013, or within 180 days after startup of the source, whichever is later.

(1) If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent than the applicable

emission limit in Table 14 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 14 no later than July 29, 2016.

(2) If you are demonstrating compliance with an emission limit in Table 14 to this subpart that is less stringent than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than October 6, 2025.

* * * * *

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 or 14 to this subpart, as applicable, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

* * * * *

■ 6. Section 63.7515 is amended by revising paragraphs (b), (c), (e), (g), and (i) to read as follows:

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

* * * * *

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 15 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 15 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 15).

* * * * *

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1 or 2 or Tables 11 through 15 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level. If sampling is conducted on 1 day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply.

* * * * *

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than 1 year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

* * * * *

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

■ 7. Section 63.7520 is amended by revising paragraph (d) to read as follows:

§ 63.7520 What stack tests and procedures must I use?

* * * * *

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 15 to this subpart.

* * * * *

■ 8. Section 63.7521 is amended by revising paragraphs (a) and (c)(1)(ii) to 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 15 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section.

* * * * *

(c) * * *

(1) * * *

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period for sampling during performance stack testing.

* * * * *

■ 9. Section 63.7522 is amended by revising paragraphs (b) introductory text, (d), (e)(1), (e)(2), (h), and (j)(1) to read as follows:

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

* * * * *

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 or 15 to this subpart as specified in paragraphs (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

* * * * *

(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 or 15 to this subpart at all times the affected units are subject to numeric emission limits following the compliance date specified in § 63.7495.

(e) * * *

(1) You must use Equation 1a or 1b or 1c to this paragraph (e)(1) to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 or 15 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

Equation 1a to paragraph (e)(1)

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

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

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

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

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

1.1 = Required discount factor.

Equation 1b to paragraph (e)(1)

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

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

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

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

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

1.1 = Required discount factor.

Equation 1c to paragraph (e)(1)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Eo \right) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq.1c)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in § 63.7575.

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

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 to this paragraph (e)(2) as an alternative to using Equation 1a of paragraph (e)(1) of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 or 15 to this subpart that are in pounds per million Btu of heat input.

Equation 2 to paragraph (e)(2)

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

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

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

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

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

1.1 = Required discount factor.

* * * * *

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 or 15 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

* * * * *

(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 to this paragraph (j)(1).

Equation 6 to paragraph (j)(1)

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

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu) or parts per million (ppm).

ELi = Appropriate emission limit from Table 2 or 15 to this subpart for unit i, in units of lb/MMBtu or ppm.

Hi = Heat input from unit i, MMBtu.

* * * * *

■ 10. Section 63.7525 is amended by revising paragraphs (a) introductory text, (a)(1), (a)(2) introductory text, (a)(2)(ii), (iv), and (vi), (l) introductory text, and (m) introductory text 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 Table 1 or 2 or Tables 11 through 15 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 (O_2) (or carbon dioxide (CO_2)) according to the procedures in paragraphs (a)(1) through (6) of this section.

(1) Install the CO CEMS including an O_2 (or CO_2) analyzer by the compliance date specified in § 63.7495. The CO and O_2 (or CO_2) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may determine compliance with the CO emissions limit using a CO_2 analyzer as the diluent monitor. If a CO_2 analyzer is used as the diluent monitor, EPA Method 19 F-factors in 40 CFR part 60, appendix A–7, for the fuel type(s) being burned in the unit and EPA Method 19 equations in 40 CFR part 60, appendix A–7, must be used to calculate the emissions corrected to 3 percent O_2 using the measured CO_2 percentage, and must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The equations used to calculate the emissions, must also account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. The methodology used to calculate the CO emissions and the methodology used to account for any CO_2 being added to, or removed from the emissions gas stream shall be detailed and approved in the site-specific monitoring plan developed according to § 63.7505(d).

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 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 this paragraph (a). 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 this paragraph (a) must use the CO CEMS to comply with the applicable alternative CO CEMS

emission standard listed in Table 1 or 2 or Tables 11 through 15 to this subpart.

* * * * *

(ii) During each relative accuracy test run of the CO CEMS, you must collect emission data for CO concurrently using both the CO CEMS and Method 10, 10A, or 10B at 40 CFR part 60, appendix A–4. The relative accuracy testing must be conducted at representative operating conditions.

* * * * *

(iv) Any CO CEMS that does not comply with this paragraph (a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Table 1 or 2 or Tables 11 through 15 to this subpart.

* * * * *

(vi) When CO_2 is used to correct CO emissions and CO_2 is measured on a wet basis, if needed, correct for moisture as follows: Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO concentrations. The following continuous moisture monitoring systems are acceptable: a continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O_2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, *i.e.,* a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (*e.g.,* hourly average wet- and dry-basis O_2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

* * * * *

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Table 1 or 2 or Tables 11 through 15 to this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date of approval of a site-specific monitoring plan.

* * * * *

(m) If your unit is subject to a HCl emission limit in Table 1 or 2 or Tables 11 through 15 to 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.

* * * * *

■ 11. Section 63.7530 is amended by revising paragraphs (b)(4)(ii)(E), (b)(4)(iii), and (h) to read as follows:

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

* * * * *

(b) * * *

(4) * * *

(ii) * * *

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Table 1 or 2 or Tables 11 through 15 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (''back half'') of the Method 5 particulate sampling train to demonstrate compliance with the PM standards in this subpart. This shall not preclude the permitting authority from requiring a determination of the ''back half'' for other purposes.

* * * * *

(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. 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.

* * * * *

(h) If you own or operate a unit subject to emission limits in Table 1 or 2 or Tables 11 through 15 to this subpart, you must meet the work practice standard according to Table 3 to this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 to this subpart.

* * * * *

■ 12. Section 63.7533 is amended by revising paragraphs (a), (e), and (f) to read as follows:

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

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 or 15 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at *https://www.epa.gov/ttn/atw/boiler/boilerpg.html.*

* * * * *

(e) The emissions rate as calculated using Equation 20 in paragraph (f) of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 or 15 to this subpart at all times the affected unit is subject to numeric emission limits, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this paragraph (f) to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 or 15 to this subpart.

Equation 20 to paragraph (f)

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

Where:

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

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

ECredits = Efficiency credits from Equation 19 to paragraph (c)(3)(i) of this section for the affected boiler.

* * * * *

■ 13. Section 63.7540 is amended by revising paragraphs (a) introductory text, (a)(8) introductory text, (a)(8)(ii), (a)(9), (a)(15) introductory text, (a)(19) introductory text, and (b) to read as follows:

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

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 15 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

* * * * *

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Table 1 or 2 or Tables 11 through 15 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

* * * * *

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Table 1 or 2 or Tables 11 through 15 to this subpart at all times the affected unit is subject to numeric emission limits.

* * * * *

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

* * * * *

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

* * * * *

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Table 1 or 2 or Tables 11 through 15 to this subpart.

* * * * *

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 15 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

* * * * *

■ 14. Section 63.7545 is amended by revising paragraph (e)(3) to read as follows:

§ 63.7545 What notifications must I submit and when?

* * * * *

(e) * * *

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Table 1 or 2 or Tables 11 through 15 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

* * * * *

■ 15. Section 63.7555 is amended by revising paragraphs (d) introductory text and (d)(5) to read as follows:

§ 63.7555 What records must I keep?

* * * * *

(d) For each boiler or process heater subject to an emission limit in Table 1 or 2 or Tables 11 through 15 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

* * * * *

(5) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 15 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

* * * * *

■ 16. Section 63.7575 is amended by:

■ a. Adding in alphabetical order the definition for ‘‘12-month rolling average’’;

■ b. Revising the definition of ‘‘Other gas 1 fuel’’; and

■ c. Revising paragraphs (3) and (4) under the definition of ‘‘Steam output.’’

The addition and revisions read as follows:

§ 63.7575 What definitions apply to this subpart?

* * * * *

12-month rolling average means the arithmetic mean of the previous 12 months of valid fuel analysis data. The 12 months should be consecutive, but not necessarily continuous if operations were intermittent.

* * * * *

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum mercury concentration of 40 micrograms/cubic meters of gas.

* * * * *

Steam output * * *

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be the appropriate emission limit from Table 1, 2, 14, or 15 to 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 paragraphs (1), (2), and (3) of this definition that includes electricity generation of paragraph (3) of this definition, 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 paragraph (2) of this definition (S_2), and the energy content of electricity generated by a electricity only turbine as paragraph (3) of this definition (MW_3) and would be calculated using Equation 1 to this definition. In the case of boilers supplying steam to one or more common headers, S_1, S_2, and $MW_{(3)}$ for each boiler would be calculated based on its (steam energy) contribution (fraction of total steam energy) to the common header.

Equation 1 to the definition *Steam Output*

$$SO_M = S_1 + S_2 + (MW_{(3)}\ x\ CFn) \qquad \text{(Eq. 1)}$$

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 paragraph (2) of this definition, MMBtu.

$MW_{(3)}$ = Electricity generated according to paragraph (3) of this definition, MWh.

CFn = Conversion factor for the appropriate subcategory for converting electricity generated according to paragraph (3) of this definition 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.

* * * * *

■ 17. 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 [c]

[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	2.1E–04 [a] lb per MMBtu of heat input.	2.9E–04 [a] lb per MMBtu of steam output or 2.7E–03 [a] 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.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS [c]—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 . . .
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)	590 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).	6.1E–01 lb per MMBtu of steam output or 6.5 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 (2.6E–05 lb per MMBtu of heat input).	1.4E–02 lb per MMBtu of steam output or 1.9E–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.	4.3E–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 (5.0E–03 lb per MMBtu of heat input).	3.5E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (5.2E–03 lb per MMBtu of steam output or 7.0E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	130 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).	1.3E–01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	4.1E–03 lb per MMBtu of heat input; or (8.4E–06[a] lb per MMBtu of heat input).	5.0E–03 lb per MMBtu of steam output or 5.8E–02 lb per MWh; or (1.1E–05[a] lb per MMBtu of steam output or 1.2E–04[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)	220 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).	0.18 lb per MMBtu of steam output or 2.5 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 (8.0E–03 lb per MMBtu of heat input).	3.1E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (8.1E–03 lb per MMBtu of steam output or 1.2E–01 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).	2.5E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	3.4E–03 lb per MMBtu of steam output or 3.5E–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).	1.1E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	2.0E–02 lb per MMBtu of steam output or 1.6E–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)	180 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).	0.22 lb per MMBtu of steam output or 2.0 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	1.5E–04[a] lb per MMBtu of heat input.	1.7E–04[a] lb per MMBtu of steam output or 2.1E–03[a] lb per MWh.	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS [c]—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 . . .
	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.
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).	1.9E–03 lb per MMBtu of heat input; or (6.1E–06 [a] lb per MMBtu of heat input).	2.1E–03 lb per MMBtu of steam output or 2.7E–02 lb per MWh; or (6.7E–6 [a] lb per MMBtu of steam output or 8.5E–5 [a] 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).	7.3E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	1.3E–02 lb per MMBtu of steam output or 7.6E–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 April 1, 2013, you may comply with the emission limits in Table 11, 12, or 13 to this subpart until January 31, 2016. On and after January 31, 2016, but before October 6, 2025 you may comply with the emission limits in Table 14 to this subpart. On and after October 6, 2025 you must comply with the emission limits in this Table 1.

[d] An owner or operator may determine compliance with the carbon monoxide emissions limit using CO_2 as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A–7, and EPA Method 19 equations in 40 CFR part 60, appendix A–7, must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit and must also take into account that the 3-percent oxygen correction is to be done on a dry basis. The methodology must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

■ 18. 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 [d]

[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	2.0E–02 lb per MMBtu of heat input	2.3E–02 lb per MMBtu of steam output or 0.26 lb per MWh.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS[d]—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 . . .
	b. Mercury	5.4E–06 lb per MMBtu of heat input	6.2E–06 lb per MMBtu of steam output or 6.9E–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).	3.9E–02 lb per MMBtu of heat input; or (5.3E–05 lb per MMBtu of heat input).	4.1E–02 lb per MMBtu of steam output or 4.8E–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)	150 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 1.6 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)	1,100 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).	1.1 lb per MMBtu of steam output or 13 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.4E–02 lb per MMBtu of heat input; or (2.0E–04 lb per MMBtu of heat input).	4.0E–02 lb per MMBtu of steam output or 4.8E–01 lb per MWh; or (2.4E–04 lb per MMBtu of steam output or 2.8E–03 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 (5.0E–03 lb per MMBtu of heat input).	3.7E–01 lb per MMBtu of steam output or 4.5 lb per MWh; or (5.9E–03 lb per MMBtu of steam output or 7.0E–02 lb per MWh).	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	210 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).	2.1E–01 lb per MMBtu of steam output or 2.3 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	7.4E–03 lb per MMBtu of heat input; or (6.4E–05 lb per MMBtu of heat input).	9.2E–03 lb per MMBtu of steam output or 0.11 lb per MWh; or (8.0E–05 lb per MMBtu of steam output or 9.0E–04 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).	4.1E–02 lb per MMBtu of heat input; or (8.0E–03 lb per MMBtu of heat input).	4.2E–02 lb per MMBtu of steam output or 5.8E–01 lb per MWh; or (8.1E–03 lb per MMBtu of steam output or 0.12 lb per MWh).	Collect a minimum of 2 dscm per run.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS[d]—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 . . .
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).	1.8E–01 lb per MMBtu of heat input; or (2.0E–03 lb per MMBtu of heat input).	2.5E–01 lb per MMBtu of steam output or 2.6 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	7.3E–07 lb per MMBtu of heat input	8.8E–07 lb per MMBtu of steam output or 1.1E–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.
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).	5.9E–02 lb per MMBtu of heat input; or (2.0E–04 lb per MMBtu of heat input).	7.2E–02 lb per MMBtu of steam output or 8.2E–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 lb per MMBtu of heat input; or (6.2E–05 lb per MMBtu of heat input).	9.6E–03 lb per MMBtu of steam output or 1.1E–01 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).	2.2E–01 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	2.7E–01 lb per MMBtu of steam output or 3.1 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.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS[d]—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 . . .
	d. Filterable PM (or TSM).	7.3E–03 lb per MMBtu of heat input or (2.1E–04 lb per MMBtu of heat input).	1.3E–02 lb per MMBtu of steam output or 7.6E–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 determine compliance with the carbon monoxide emissions limit be determined using CO_2 as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A–7, and EPA Method 19 equations in 40 CFR part 60, appendix A–7, must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit and must also take into account that the 3-percent oxygen correction is to be done on a dry basis. The methodology must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[d] Before October 6, 2025 you may comply with the emission limits in Table 15 to this subpart. On and after October 6, 2025], you must comply with the emission limits in this Table 2.

■ 19. Table 3 of subpart DDDDD of part 63 is amended by revising the entries "5." and "6." to read as follows:

* * * * *

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

If your unit is . . .	You must meet the following . . .
* * * * * * *	
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 15 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, clean dry biomass, 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 choose to comply using paragraph (1) of the definition of "startup" in § 63.7575, once you start firing fuels that are not clean fuels 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, and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, 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 paragraph (2) of the definition of "startup" in § 63.7575, once you start to feed fuels that are not clean fuels, 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 engage and operate PM control within one hour of first feeding fuels that are not clean fuels[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. You must develop and implement a written startup and shutdown plan, as specified in § 63.7505(e). 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 Table 1 or 2 or Tables 11 through 15 to this subpart during shutdown.	You must operate all CMS during shutdown. While firing fuels that are not clean fuels 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, 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.

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

If your unit is . . .	You must meet the following . . .
	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] As specified in § 63.7555(d)(13), the source may request an alternative timeframe with the PM controls requirement to the permitting authority (state, local, or tribal agency) that has been delegated authority for this subpart by EPA. The source must provide evidence that (1) it is unable to safely engage and operate the PM control(s) to meet the "fuel firing + 1 hour" requirement and (2) the PM control device is appropriately designed and sized to meet the filterable PM emission limit. It is acknowledged that there may be another control device that has been installed other than ESP that provides additional PM control (*e.g.,* scrubber).

■ 20. Table 4 to subpart DDDDD of part 63 is amended by revising the column headings to read as follows:

* * * * *

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

When complying with a numerical emission limit under Table 1, 2, 11, 12, 13, 14, or 15 of this subpart using . . .	You must meet these operating limits . . .

* * * * * * *

* * * * *

■ 21. 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 [a b]

[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.
	c. Opacity	i. Establish a site-specific maximum opacity level.	(1) Data from the opacity monitoring system during the PM performance test.	(a) You must collect opacity readings every 15 minutes during the entire period of the performance tests. (b) Determine the average hourly opacity reading by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS [a] [b]—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
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. (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.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS [a] [b]—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
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 highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

[a] Operating limits must be confirmed or reestablished during performance tests.

[b] 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. For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests. For maximum operating load, if you conduct multiple performance tests, you must set the maximum operating load at the lower of the maximum values established during the performance tests.

■ 22. Table 8 to subpart DDDDD of part 63 is amended by revising entry ''8.'' to read as follows:

* * * * *

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

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
* * * * * * *	
8. Emission limits using fuel analysis.	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and b. Reduce the data to 12-month rolling averages; and c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 15 to this subpart. d. Calculate the HCl, mercury, and/or TSM emission rate from the boiler or process heater in units of lb/MMBtu using Equation 15 and Equations 16, 17, and/or 18 in § 63.7530.
* * * * * * *	

■ 23. 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.

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 . . .
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
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.

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 . . .
	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
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 determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A–7, and EPA Method 19 equations in 40 CFR part 60, appendix A–7, must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

■ 24. 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.
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.

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. 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.
	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 determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A–7, and EPA Method 19 equations in 40 CFR part 60, appendix A–7, must be used to generate the appropriate CO$_2$ correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO$_2$ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

■ 25. Table 13 to subpart DDDDD is of part 63 is revised to read as follows:

Table 13 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before April 1, 2013

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	8.6E–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.
2. 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.
	b. Filterable PM (or TSM)	1.1E–03 lb per MMBtu of heat input; or (2.8E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
3. 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.
	b. Filterable PM (or TSM)	2.8E–02 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
4. 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.
	b. 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. 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.
	b. 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.
6. 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 (410 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 (2.6E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
7. 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)	3.2E–01 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
8. 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.
9. 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)	5.1E–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.
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (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)	3.6E–02 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
11. 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.

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE APRIL 1, 2013—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 . . .
12. 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.
13. Units designed to burn liquid fuel.	a. HCl	1.2E–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.
	b. Mercury	4.9E–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.
14. Units designed to burn heavy liquid fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E–03 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
15. Units designed to burn light liquid fuel.	a. CO (or CEMS)	130 [a] ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 1-day block average)..	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).	Collect a minimum of 3 dscm per run.
16. 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; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 3-hour rolling 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).	Collect a minimum of 2 dscm per run.
17. 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 and you are not required to conduct testing for CEMS or CPMS monitor certification, 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 determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A–7, and EPA Method 19 equations in 40 CFR part 60, appendix A–7, must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

■ 26. Add Table 14 to subpart DDDDD of part 63 to read as follows:

TABLE 14 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS [c]

[As stated in § 63.7500, you may continue to comply with the following applicable emission limits until October 6, 2025: [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.

TABLE 14 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS[c]—Continued

[As stated in § 63.7500, you may continue to comply with the following applicable emission limits until October 6, 2025: [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 . . .
	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.
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.

TABLE 14 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS [c]—Continued

[As stated in § 63.7500, you may continue to comply with the following applicable emission limits until October 6, 2025: [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 . . .
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 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.
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 [a] 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 [a] lb per MMBtu of steam output or 1.1E–03 [a] 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.

Table 14 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters [c]—Continued

[As stated in § 63.7500, you may continue to comply with the following applicable emission limits until October 6, 2025: [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 . . .
	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 April 1, 2013, you may comply with the emission limits in Table 11, 12, or 13 to this subpart until January 31, 2016. On and after January 31, 2016, but before October 6, 2025 you may comply with the emission limits in this Table 14. On and after October 6, 2025, you must comply with the emission limits in Table 1 to this subpart.

[d] An owner or operator may determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A–7, and EPA Method 19 equations in 40 CFR part 60, appendix A–7, must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

■ 27. Add Table 15 to subpart DDDDD of part 63 to read as follows:

Table 15 to Subpart DDDDD of Part 63—Alternative Emission Limits for Existing Boilers and Process Heaters [D]

[As stated in § 63.7500, you may continue to comply with following emission limits until October 6, 2025: [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.

TABLE 15 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS[D]—Continued

[As stated in § 63.7500, you may continue to comply with following emission limits until October 6, 2025: [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 . . .
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.
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 lb per MMBtu of heat input	2.5E–06 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 15 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS [d]—Continued

[As stated in § 63.7500, you may continue to comply with following emission limits until October 6, 2025: [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 lb per MMBtu of heat input; or (6.2E–05 lb per MMBtu of heat input).	9.6E–03 lb per MMBtu of steam output or 1.1E–01 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 three 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 determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A–7, and EPA Method 19 equations in 40 CFR part 60, appendix A–7, must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The methodology must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[d] Before October 6, 2025 you may comply with the emission limits in this Table 15. On and after October 6, 2025, you must comply with the emission limits in Table 2 to this subpart.

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