6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA-HQ-OAR-2018-0794; FRL-6716.4-02-OAR-]

RIN 2060-AW68

National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units: Final Repeal

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is finalizing the repeal of specific amendments to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs), commonly referred to as the Mercury and Air Toxics Standards (MATS), that were promulgated on May 7, 2024. Specifically, the EPA is repealing the revised filterable particulate matter (fPM) emission standard, which serves as a surrogate for non-mercury hazardous air pollutant (HAP) metals for existing coal-fired EGUs; the revised fPM emission standard compliance demonstration requirements; and the revised mercury (Hg) emission standard for lignite-fired EGUs. The EPA is also making technical, non-substantive clarifications to electronic reporting requirements.

DATES: The final rule is effective on **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. The Director of the *Federal*

Register (FR) has approved incorporation by reference (IBR) of certain publications listed in the rule as of **[INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

ADDRESSES: The EPA established a docket for this action under Docket ID No. EPA-HQ-OAR-2018-0794. All documents in the docket are available 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. The EPA does not place certain other material, such as copyrighted material, on the Internet; this material is publicly available only as Portable Document Format (PDF) versions and accessible only on EPA computers in the docket office reading room. The public cannot download certain databases and physical items from the docket but may request these items by contacting the docket office by telephone at (202) 566-1744. The docket office has 10 business days to respond to such requests. Except for these items, publicly available docket materials are available electronically at *https://www.regulations.gov* or on the EPA computers in the docket office reading room at the EPA Docket Center, WJC West Building, Room Number 3334, 1301 Constitution Ave., NW, Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Time (ET), Monday through Friday. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the EPA Docket Center is (202) 566-1742.

FOR FURTHER INFORMATION CONTACT: For information about this final rule, contact Christopher Werner, Industrial Processing and Power Division (IPPD) (D243-01), Office of Clean Air Programs (OCAP), U.S. Environmental Protection Agency, P.O.

Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-5133; and email address: *werner.christopher@epa.gov*. Individuals who are deaf or hard of hearing, as well as individuals who have speech or communication disabilities, may use a telecommunications relay service. To learn more about how to make an accessible telephone call to any of the telephone numbers shown in this preamble, please visit the webpage[1] for the relay service of the Federal Communications Commission, and a list of relay services is available on their directory page.[2]

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. Throughout this notice the use of "we," "us," or "our" refers to the EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACI	activated carbon injection
BLDS	bag leak detection systems
BTF	beyond the floor
Btu	British thermal units
CAA	Clean Air Act
CEMS	continuous emission monitoring system(s)
CFB	circulating fluidized bed
CFR	Code of Federal Regulations
CPMS	continuous parametric monitoring system(s)
CRA	Congressional Review Act
EAV	equivalent annualized values
ECMPS	Emissions Collection and Monitoring Plan System
EGU	electric utility steam generating unit
EIA	U.S. Energy Information Administration
ESP	electrostatic precipitator
FF	fabric filter
FGD	flue gas desulfurization

[1] *See* https://www.fcc.gov/trs.
[2] *See* https://www.fcc.gov/general/trs-state-and-territories.

fPM	filterable particulate matter
FR	*Federal Register*
GACT	generally available control technologies
GWh	gigawatt-hour
HAP	hazardous air pollutant(s)
HCl	hydrogen chloride
HF	hydrogen fluoride
Hg	mercury
HQ	hazard quotient
ICR	Information Collection Request
IGCC	integrated gasification combined cycle
IPPD	Industrial Processing and Power Division
IRA	Inflation Reduction Act
lb	pounds
LEE	low emitting EGU
MATS	Mercury and Air Toxics Standards
MMBtu	million British thermal units of heat input
MW	megawatt
NAICS	North American Industry Classification System
NESHAP	national emission standards for hazardous air pollutants
NTTAA	National Technology Transfer and Advancement Act
OCAP	Office of Clean Air Programs
OMB	Office of Management and Budget
PDF	Portable Document Format
PM	particulate matter
PM CEMS	particulate matter continuous emission monitoring system(s)
PRA	Paperwork Reduction Act
PV	present values
REL	reference exposure level
RFA	Regulatory Flexibility Act
RIA	Regulatory Impact Analysis
RIN	Regulatory Information Number
RTR	residual risk and technology review
SO_2	sulfur dioxide
SO_3	sulfur trioxide
TBtu	trillion British thermal units of heat input
TOSHI	target organ-specific hazard index
tpy	tons per year
UMRA	Unfunded Mandates Reform Act
XML	Extensible Markup Language

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I. General Information

A. Executive Summary

In 2012, the EPA promulgated standards to address HAP emissions—including mercury, lead, arsenic, chromium, nickel, and cadmium, as well as hydrogen chloride from coal- and oil-fired EGUs ("2012 MATS Rule").[3] Under CAA section 112, the EPA was required to review the standards within eight years to identify and address any residual risk to human health and the environment and, separately, to revise the standards as "necessary" in light of developments in practices, processes, and control technologies.[4] The Agency timely completed these reviews in 2020, finding, among other things, that the existing standards in the 2012 MATS Rule protected public health with an ample margin of safety and that further changes to the standards were not "necessary" because there were no cost-effective developments in technology that supported revision ("2020 Final Rule").[5]

Following a change in administration, however, an Executive Order instructed the EPA to reconsider and suspend, revise, or rescind the 2020 Final Rule if appropriate.[6] On May 7, 2024, the EPA finalized several MATS amendments after initiating a rulemaking in response to the Executive Order ("2024 Final Rule").[7] In the 2024 Final Rule, the EPA confirmed that the 2020 risk review finding that the 2012 MATS Rule protected public health and the environment with an ample margin of safety as required by CAA section

[3] 77 FR 9304 (February 16, 2012).
[4] CAA section 112(d)(6), (f)(2). CAA section 112 is codified at 42 U.S.C. 7412.
[5] 85 FR 31286 (May 22, 2020).
[6] Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," 86 FR 7037 (January 25, 2021), since rescinded by Executive Order 14148, "Initial Rescissions of Harmful Executive Orders and Actions," 90 FR 8237 (January 28, 2025).
[7] 89 FR 38508 (May 7, 2024).

112(f)(2) was correct.[8] Nevertheless, upon reconsideration of the technology review under section 112(d)(6), the Agency established more stringent standards for the non-Hg metal HAP emissions and for fPM emissions (which serves as a surrogate for non-Hg metal HAP) from coal-fired EGUs and for mercury emissions from lignite-fired units and required all EGUs to install continuous emissions monitoring systems (CEMS) to monitor emissions of fPM, thereby removing existing compliance flexibilities in favor of a uniform, one-size-fits-all approach. The Agency reasoned that the revisions to MATS were warranted because “the size and unique nature of the coal-fired power sector” made the revisions “necessary,” but the revisions were based on relatively limited data concerning potential improvements in control technology and established despite the fact that the costs of the revisions were and are higher than anything the Agency has previously determined “necessary” pursuant to section 112(d)(6).[9]

On March 12, 2025, Administrator Zeldin announced that the Agency would reconsider the 2024 Final Rule.[10] On June 17, 2025, the EPA undertook a review of the 2024 Final Rule and proposed to repeal most of its amendments (“2025 Proposal”).[11] This action was consistent with several Executive Orders and other Presidential Actions. In particular, Executive Order 14154, “Unleashing American Energy,” specifies that it is the policy of the United States to “protect the United States’s economic and national security and military preparedness by ensuring that an abundant supply of reliable energy is readily accessible in every State and territory of the Nation” and “to ensure that all

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[8] *Id.* at 38518; *see* 88 FR 24866 (April 24, 2023) (proposed rule for the 2024 Final Rule).
[9] 89 FR 38534 (May 7, 2024).
[10] https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history.
[11] 90 FR 25535 (June 17, 2025).

regulatory requirements related to energy are grounded in clearly applicable law" (among other considerations).[12] The Executive Order directed the heads of all agencies to review all existing regulations to identify agency actions that impose an undue burden on the identification, development, or use of domestic energy resources, with particular attention to oil, natural gas, coal, hydropower, biofuels, critical minerals, and nuclear energy resources. This Executive Order also directed agencies, consistent with applicable law, to suspend, revise, or rescind all agency actions identified as unduly burdensome and revoked Executive Order 13990. This Executive Order was followed by Executive Order 14179, "Removing Barriers to American Leadership in Artificial Intelligence;"[13] Executive Order 14192, "Unleashing Prosperity Through Deregulation;"[14] Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid;"[15] and Executive Order 14261, "Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241," 90 FR 15517 (April 14, 2025).

In addition, on April 8, 2025, President Trump signed a Proclamation titled "Regulatory Relief for Certain Stationary Sources to Promote American Energy."[16] This Proclamation exempted certain stationary sources, identified in Annex 1 of the Proclamation, from compliance with the 2024 Final Rule pursuant to CAA section 112(i)(4).[17] The President's exemption is for a period of two years beyond the 2024 Final

[12] 90 FR 8353 (January 29, 2025).
[13] 90 FR 8741 (January 31, 2025).
[14] 90 FR 9065 (February 6, 2025).
[15] 90 FR 15521 (April 14, 2025).
[16] 90 FR 16777 (April 21, 2025).
[17] "Regulatory Relief for Certain Stationary Sources to Further Promote American Energy" was issued on July 17, 2025, and added six sources to Annex 1. *See* 90 FR 34583 (July 23, 2025).

Rule's compliance date (*i.e.*, for the period beginning July 8, 2027, and concluding July 8, 2029). Sources identified in Annex 1 will remain subject to the 2012 MATS Rule during the two-year extension period. Copies of the Presidential Proclamation and Annex 1 are available in the rulemaking docket.[18]

In the 2025 Proposal, the EPA proposed to repeal the three key amendments finalized in the 2024 Final Rule based on the EPA's authority under CAA section 112 and the EPA's authority to reconsider previous decisions taken under that authority to the extent permitted by law and supported by a reasoned explanation.[19] The Agency noted that the proposed repeal was in accordance with the above-noted Executive Orders and solicited comment on whether the 2024 Final Rule had erred in evaluating cost-effectiveness and technical feasibility when deciding that revisions were "necessary."[20] In addition, the Agency sought comment on whether it should consider the potential for meaningful risk reduction when evaluating costs as part of determining whether revisions are "necessary" in a technology review.[21]

In this final rule, the EPA is repealing the following three MATS amendments from the 2024 Final Rule:

- The fPM emission standard for existing coal-fired EGUs, which the EPA revised from 0.030 pounds per million British thermal units (lb/MMBtu) to 0.010 lb/MMBtu;

[18] Document ID No. EPA-HQ-OAR-2018-0794-6980.
[19] *FDA v. Wages & White Lion Invs., L.L.C.*, 604 U.S. 542, 568 (2025); *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009); *see also Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 42 (1983).
[20] 90 FR 25544-45 (June 17, 2025).
[21] *Id.* at 25545.

- The compliance demonstration requirement for the fPM emission standard for all coal- and oil-fired EGUs, which the EPA revised from allowing EGU owners and operators to choose between use of quarterly stack testing, use of continuous parametric monitoring systems (CPMS), or use of PM continuous emission monitoring systems (CEMS) to allowing only the use of PM CEMS; and
- The Hg emission standard for existing lignite-fired EGUs, which the EPA revised from 4.0 pounds per trillion British thermal units (lb/TBtu) to 1.2 lb/TBtu.

The EPA has reevaluated the 2024 Final Rule and, after considering public comments, finds that the revisions to the emissions standards were not "necessary" because they impose unwarranted compliance costs or raise potential technical feasibility concerns. With respect to the revised fPM emission standard, the EPA has two separate, and severable, bases for this finding. First, the EPA finds that the cost-effectiveness values associated with this standard (*i.e.*, the cost per mass of fPM or non-Hg HAP metal(s) reduced) are significantly higher than cost-effectiveness values that the Agency previously accepted in other technology reviews and related CAA section 112 actions for which cost is a factor. Unlike in the 2024 Final Rule, the Agency does not believe it is consistent with prior practice or reasonable to disregard such cost-effectiveness comparators and does not believe that differences between the EGU source category and other source categories justify establishment of a new high-cost benchmark for fPM as a surrogate for non-Hg metal HAP. Second, in undertaking review of the 2024 rule, the EPA also considered the Agency's conclusion from the 2020 residual risk review, confirmed by the 2024 Final Rule, that there is little risk remaining from emissions of non-Hg HAP metals following the implementation of the emissions standards promulgated in the 2012 MATS Rule. For the reasons set forth later in this preamble, the Agency concludes that the low levels of remaining risk found in the prior residual risk review are relevant to the cost reasonableness of revised standards and therefore to whether it is “necessary” to promulgate revised standards that impose additional costs.

With respect to the requirement to utilize PM CEMS for compliance demonstrations, the EPA finds this requirement is an unnecessary expense for coal- and oil-fired EGUs and that owners and operators should retain the option of using other monitoring methods to demonstrate compliance with the fPM emission standard. For the reasons set forth later in this preamble, mandating the use of PM CEMS and removing previously available compliance alternatives was not “necessary” pursuant to CAA section 112(d)(6). Furthermore, although the EPA in the 2024 Final Rule invoked CAA section 114(a)(1)(C) as offering additional authority for the PM CEMS requirement, that provision is equally applicable to the alternative compliance demonstration options restored in this final rule.

Finally, the EPA finds that the revised Hg emission standard for lignite-fired EGUs is not achievable given the broad range of boiler types and varying compositions of the different lignite fuels used at those facilities. As set forth later in this preamble, in light of this variability, the revised standard was based on insufficient data. As a result, the EPA finds that these revisions to the emission standards were not “necessary” under CAA section 112(d)(6), and is repealing them. As noted above, this action is consistent with Executive Order 14192, “Unleashing Prosperity Through Deregulation,”[22]

[22] 90 FR 9065 (February 6, 2025).

Executive Order 14154, "Unleashing American Energy,"[23] and Executive Order 14261, "Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241,"[24] among other recent Presidential actions.

The EPA estimates that this action will result in present value cost savings of $670 million at a 3 percent discount rate and $490 million at a 7 percent discount rate over the 2028 to 2037 timeframe, with total annualized cost savings of $78 and $69 million per year, respectively (in 2024 dollars).

B. Does this action apply to me?

Regulated entities. Table 1 of this preamble presents categories and entities that this action potentially regulates.

Table 1—NESHAP and Industrial Source Categories Affected By This Final Action

NESHAP and Source Category	NAICS[1] Code
Coal and oil-fired EGUs (40 CFR part 63, subpart UUUUU)	221112, 221122, 921150

[1] North American Industry Classification System (NAICS).

The EPA does not intend Table 1 of this preamble to be exhaustive but rather to provide a guide for readers regarding the entities that this final action likely affects. To determine if this action affects your facility, you should examine the applicability criteria in title 40 of the Code of Federal Regulations (CFR), part 63, subpart UUUUU. If you have any questions regarding the applicability of any aspect of this NESHAP, please contact the appropriate person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section of this preamble.

[23] 90 FR 8353 (January 29, 2025).
[24] 90 FR 15517 (April 14, 2025).

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

In addition to the docket, an electronic copy of this final rule is available on the Internet. A brief summary of this rule is available at *https://www.regulations.gov*, Docket ID No. EPA-HQ-OAR-2018-0794. Following signature by the EPA Administrator, the EPA will post a copy of this rule at: *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards*. Following publication in the *Federal Register*, the EPA will post the *Federal Register* version and key technical documents at this same website.

The changes to the regulatory text are being finalized in today's notice. In addition, a redline strikeout memorandum showing the rule edits necessary to incorporate the changes to 40 CFR part 63, subpart UUUUU, finalized in this action is available in the docket. Following signature by the Administrator, the EPA also will post a copy of this preamble to *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards*.

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 ("D.C. Circuit") by **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].** CAA section 307(b)(2) prohibits a party from challenging this final rule separately in any civil or criminal proceedings brought by the EPA for enforcement.

CAA section 307(d)(7)(B) further provides that only an objection to a rule or procedure that was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. This section also requires 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

A. What is the authority for this action?

1. What is the statutory authority for this action?

The statutory authority for this action is provided by CAA section 112, as amended (42 U.S.C. 7412). CAA section 112 establishes a multi-stage regulatory process to develop standards for emissions of HAP from stationary sources. Generally, the first stage involves establishing technology-based standards that reflect the maximum achievable control technology (MACT) or an appropriate alternative.[25] The second stage involves evaluating those standards within eight years under CAA section 112(f)(2) to determine whether additional standards are needed to address any remaining risk

[25] 42 U.S.C. 7412(d)(1)-(4).

associated with HAP emissions.[26] This second stage is commonly referred to as the "residual risk review." In addition to the residual risk review, CAA section 112(d)(6) also requires the EPA to review the standards every eight years and "revise as necessary" taking into account "developments in practices, processes, and control technologies."[27] This review is commonly referred to as the "technology review." The discussion that follows identifies the most relevant statutory sections and briefly explains the contours of the methodology used to implement these statutory requirements.

In the first stage of the CAA section 112 standard-setting process, the EPA promulgates technology-based standards under CAA section 112(d) for categories of sources identified as emitting one or more of the HAP listed in CAA section 112(b). Sources of HAP emissions are either major sources or area sources, and CAA section 112 establishes different requirements for major source standards and area source standards. The requirements for major sources are the relevant requirements for the present rulemaking. "Major sources" are those that emit or have the potential to emit 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of any combination of HAP.[28] For major sources, CAA section 112(d)(2) provides that the technology-based NESHAP must reflect 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. CAA section 112(d)(3) also establishes a minimum control level for MACT standards, known as the MACT "floor," which is based on emission controls achieved in practice by a certain

[26] *Id.* 7412(f)(2).
[27] *Id.* 7412(d)(6).
[28] *Id.* 7412(a)(1).

percentage of the best performing sources. The EPA also considers control options that are more stringent than the floor. Standards more stringent than the floor are commonly referred to as "beyond-the-floor" standards.

The next stage in standard-setting focuses on identifying and addressing any remaining (*i.e.*, "residual") risk within eight years pursuant to CAA section 112(f)(2) and concurrently conducting a technology review pursuant to CAA section 112(d)(6). This latter provision requires the EPA to review standards promulgated under CAA section 112 and revise them "as necessary (taking into account developments in practices, processes, and control technologies)" no less often than every eight years. In conducting this review, which we call the "technology review," the EPA is not required to recalculate the MACT floors that were established in earlier rulemakings.[29] The EPA considers cost in deciding whether to revise the standards pursuant to CAA section 112(d)(6).

CAA section 112(d)(6) and relevant case law provide the EPA with flexibility to consider additional relevant factors other than those enumerated in section 112(d)(6) when deciding whether revisions to existing standards are "necessary." The D.C. Circuit has held that the CAA section 112(d)(6) requirement to periodically review and revise CAA section 112 emission standards "as necessary" is not limited to the consideration of "developments in practices, processes and control technologies."[30] Rather, "the operative standard is 'revise as necessary,' with the parenthetical pointing to a non-exhaustive list of considerations."[31] The Supreme Court also emphasized in *Michigan v. EPA* that unless

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[29] *Ass'n of Battery Recyclers, Inc. v. EPA*, 716 F.3d 667 (D.C. Cir. 2013); *Natural Resources Def. Council (NRDC) v. EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008).
[30] *La. Envtl. Action Network (LEAN) v. EPA*, 955 F.3d 1088, 1097 (D.C. Cir. 2020).
[31] *Id.*; *see also Nat'l Ass'n for Surface Finishing v. EPA*, 795 F.3d 1, 11 (D.C. Cir. 2015); *Ass'n of Battery Recyclers*, 716 F.3d at 673-74.

the statute provides otherwise, broad terms such as "necessary" direct the relevant agency to consider all relevant factors, including by assessing the cost of an action relative to the anticipated benefits.[32] That decision is particularly relevant here because the Court was interpreting a related provision of CAA section 112 that instructs the Administrator to determine whether it is "appropriate and necessary" to regulate HAP emissions from EGUs.[33] Thus, under relevant case law, when the EPA is deciding whether it is "necessary" to revise standards pursuant to CAA section 112(d)(6), the Agency can consider the costs of any developments in practices, processes, and control technologies.

The EPA is also finalizing that the results of a prior residual risk review under CAA section 112(f)(2) can be relevant under certain circumstances when evaluating whether it is "necessary" to revise standards under CAA section 112(d)(6). Specifically, as relevant here, where the remaining risk of cancer from the sources in this category is below 1-in-1 million, cost considerations bear additional weight in determining whether revised standards are "necessary" under CAA section 112(d)(6). In section III.A.2 of this preamble, we elaborate on this approach, including discussing its basis in CAA section 112 and its consistency with prior NESHAP technology reviews.

2. What is the authority for revisiting the 2024 Final Rule?

The EPA's authority to revisit existing regulations under CAA section 112 is well-grounded in law. Specifically, the EPA has authority to reconsider, repeal, or revise past decisions to the extent permitted by law so long as the Agency provides a reasoned

[32] 576 U.S. 743, 752-53 (2015).
[33] *See id.* (interpreting 42 U.S.C. 7412(n)(1)(A)).

explanation.[34] This is true when, as is the case here, an agency reconsiders a prior regulation after a change in administration.[35] When permitted by the statutory scheme, "[a]gencies obviously have broad discretion to reconsider a regulation at any time."[36]

B. What is the coal- and oil-fired EGU source category, and how does the NESHAP regulate emissions from the source category?

The EPA promulgated the Mercury and Air Toxics Standards on February 16, 2012. The standards are codified at 40 CFR part 63, subpart UUUUU. Coal- and oil-fired EGUs are combustion units of more than 25 megawatts (MW) that serve a generator that produces electricity for sale and are located at both major and area sources of HAP emissions.[37] For coal-fired EGUs, the 2012 MATS Rule established standards to limit emissions of Hg, acid gas HAP (*e.g.*, hydrogen chloride (HCl), hydrogen fluoride (HF)), non-Hg HAP metals (*e.g.*, nickel, lead, chromium), and organic HAP (*e.g.*,

[34] *See, e.g.*, *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 42 ("[R]egulatory agencies do not establish rules of conduct to last forever [and] an agency must be given able latitude to adapt their rules and policies to . . . changing circumstances."); *see also Clean Water Action v. EPA*, 936 F.3d 308, 313 (5th Cir. 2019) ("EPA correctly surmised that, in addition to its statutory authority to revise rules . . . administrative agencies possess the inherent authority to revise previously-promulgated rules, so long as they follow the proper administrative requirements and provide a reasoned basis for the agency decision.").

[35] *Nat'l Ass'n of Home Builders v. EPA*, 682 F.3d 1032, 1038, 1043 (D.C. Cir. 2012) (explaining that an agency's "reevaluation of which policy would be better in light of the facts" is "well within" its discretion and that a change in administration is a "perfectly reasonable basis for an executive agency's reappraisal of the costs and benefits of its programs and regulations" (internal quotation marks omitted)). For this rulemaking, no commenters contested that the EPA has authority to reconsider a prior rule under CAA section 112(d)(6), although some argued that the EPA is impermissibly weakening a prior CAA section 112 rule.

[36] *Clean Air Council v. Pruitt*, 862 F.3d 1, 8-9 (D.C. Cir. 2017).

[37] A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale is also an electric utility steam generating unit.

formaldehyde, dioxin/furan). Emission standards for HCl serve as a surrogate for all the acid gas HAP. For coal-fired EGUs with flue gas desulfurization (FGD), an alternate standard for sulfur dioxide (SO_2) may be used as a surrogate for all acid gas HAP if SO_2 CEMS are installed and operational. Standards for fPM serve as a surrogate for the non-Hg HAP metals, with total and individual HAP metals standards provided as an alternative. The EPA chose fPM as a surrogate for non-Hg HAP metals because non-Hg HAP metals are predominantly a component of the filterable fraction of total PM (which is composed of a filterable and condensable fraction), and control of fPM emissions also results in control of emissions of non-Hg HAP metals.[38] Additionally, not all fuels emit the same type and amount of non-Hg HAP metals, but most generally emit fPM that includes some amount and combination of all the non-Hg HAP metals. Finally, using fPM as a surrogate eliminates the cost of performance testing to demonstrate compliance with numerous standards for individual non-Hg HAP metals.[39]

In addition, the EPA established work practice standards to limit the formation and emissions of organic HAP. For oil-fired EGUs, the 2012 MATS Rule established standards to limit emissions of HCl and HF, total HAP metals (*e.g.*, Hg, nickel, lead), and organic HAP (*e.g.*, formaldehyde, dioxin/furan). Standards for fPM also serve as a surrogate for total HAP metals, with standards for total and individual HAP metals provided as alternative equivalent standards.

C. Summary of the 2020 Final Rule

The 2020 Final Rule included two separate decisions. First, the EPA responded to

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[38] Selenium may be present in the filterable PM or the condensable fraction as the acid gas, SeO_2.

[39] Document ID No. EPA-HQ-OAR-2009-0234.

the Supreme Court's remand in *Michigan* by concluding that it is not "appropriate and necessary" pursuant to CAA section 112(n)(1)(A) to regulate coal- and oil-fired EGUs under CAA section 112.[40] Second, the EPA completed the combined RTR for MATS due 8 years from the promulgation of the 2012 MATS Rule. As part of the RTR, the EPA conducted the residual risk review ("2020 Residual Risk Review") pursuant to CAA section 112(f)(2), which requires the EPA to determine whether promulgation of additional standards is needed to provide an ample margin of safety to protect public health or to prevent an adverse environmental effect. Also, the EPA conducted a technology review ("2020 Technology Review") pursuant to CAA section 112(d)(6), which focused on identifying and evaluating developments in practices, processes, and control technologies that occurred since promulgation of the 2012 MATS Rule to determine whether revisions to the standards were otherwise "necessary."

The EPA presented the results of the 2020 Residual Risk Review, including the Agency's decisions regarding risk acceptability, ample margin of safety, and adverse environmental effects, in the 2020 Final Rule. Table 2 below summarizes the results of the risk assessment; more detail is available in the document entitled *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule*, which is available in the docket for this rulemaking.[41] The EPA found the residual risk due to emissions of air toxics from this

[40] As noted below, in 2023, the EPA reversed its position from the 2020 Final Rule and concluded that regulation of coal- and oil-fired EGUs is "appropriate and necessary" under CAA section 112(n)(1)(A). 88 FR 13956 (March 6, 2023) ("2023 Final Rule"). In the present rulemaking, the EPA is not reconsidering the "appropriate and necessary" finding in the 2020 Final Rule or 2023 Final Rule.
[41] Document ID No. EPA-HQ-OAR-2018-0794-4553.

source category to be acceptable and determined that the 2012 MATS Rule provided an ample margin of safety to protect public health and prevent adverse environmental effects. Therefore, the EPA did not make any revisions to the 2012 MATS Rule to address residual risk.

Table 2—Coal- and Oil-Fired EGU Inhalation Risk Assessment Results in the 2020 Final Rule (85 FR 31286, May 22, 2020)

Number of Facilities[1]	Maximum Individual Cancer Risk (in 1 million)[2]		Population at Increased Risk of Cancer ≥ 1-in-1 million		Annual Cancer Incidence (cases per year)		Maximum Chronic Noncancer TOSHI[3]		Maximum Screening Acute Noncancer HQ[4]
322	Based on . . .		Based on . . .		Based on . . .		Based on . . .		Based on Actual Emissions Level
	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	
	9	10	193,000	636,000	0.04	0.1	0.2	0.4	HQ_{REL} = 0.09 (arsenic)

[1] Number of facilities evaluated in the risk analysis. At the time of the risk analysis there were an estimated 323 facilities in the coal- and oil-fired EGU source category; however, one facility is in Guam, which was beyond the geographic range of the model used to estimate risks. Therefore, the Guam facility was not modeled and the emissions for that facility were not included in the assessment.
[2] Maximum individual excess lifetime cancer risk due to HAP emissions from the source category.
[3] Maximum target organ-specific hazard index (TOSHI). The target organ systems with the highest TOSHI for the source category are respiratory and immunological.
[4] The maximum estimated acute exposure concentration was divided by available short-term threshold values to develop an array of hazard quotient (HQ) values. HQ values shown use the lowest available acute threshold value, which in most cases is the reference exposure level (REL). When an HQ exceeds 1.0, we also show the HQ using the next lowest available acute dose-response value.

The 2020 Residual Risk Review also included more particularized risk determinations. As relevant here, these included determining that the maximum lifetime cancer risk from coal-fired EGUs ranged from 0.002-in-1 million to 0.3-in-1 million.[42]

The 2020 Final Rule also presented the results of the 2020 Technology Review, which focused on identifying and evaluating developments in practices, processes, and control technologies that occurred since promulgation of the 2012 MATS Rule to determine whether revisions are "necessary" in light of all relevant considerations. Control technologies typically used to minimize emissions of pollutants that have numeric emission limits under the 2012 MATS Rule include electrostatic precipitators (ESPs) and fabric filters (FFs) for control of fPM as a surrogate for non-Hg HAP metals; wet scrubbers, dry scrubbers, and dry sorbent injection for control of acid gases (*e.g.*, SO_2, HCl, and HF); and activated carbon injection (ACI) and other Hg-specific technologies for control of Hg. In the 2020 Technology Review, the EPA did not identify any developments in practices, processes, or control technologies that would achieve further cost-effective emissions reductions and thus did not make any changes to the emission standards or other requirements in the 2012 MATS Rule. More information on the 2020 Technology Review is presented in the memorandum entitled *Technology Review for the Coal- and Oil-Fired EGU Source Category*, which is available in the docket for this rulemaking.[43]

D. Summary of the 2024 Review of the 2020 Final Rule

Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," instructed the EPA to review the 2020

[42] *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule.* This report is referred to as the 2020 Residual Risk Review throughout the preamble.
[43] Document ID No. EPA-HQ-OAR-2018-0794-0015.

Final Rule and to consider publishing a notice of proposed rulemaking suspending, revising, or rescinding that action.[44] The EPA reviewed the finding in the 2020 Final Rule that it was not appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and, on February 9, 2022, proposed to find that it is appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112.[45] The EPA made the affirmative finding on March 6, 2023.[46]

On April 24, 2023, the EPA proposed the results of the Agency's review of the RTR from the 2020 Final Rule.[47] In the 2023 proposed rule, the EPA noted the conclusions from the 2020 Residual Risk Review, as shown in Table 2 of this preamble, including the finding that residual risk due to emissions of air toxics from this source category was acceptable and that the 2012 MATS Rule provided an ample margin of safety to protect public health and prevent adverse environmental effects. Further, the EPA explained that it had "review[ed] the 2020 residual risk analysis, [and] . . . determined that the risk analysis was rigorous, robust, and conducted using approaches and methodologies that are consistent with those that have been utilized in residual risk analyses and reviews for other industrial sectors."[48] For these reasons, the EPA did not reopen the 2020 Residual Risk Review and did not propose changes to any emissions standards or other requirements for the purpose of addressing the remaining risk.[49]

The EPA's review of the 2020 Technology Review included evaluating the

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[44] 86 FR 7037 (January 25, 2021), rescinded by Executive Order 14148, "Initial Rescissions of Harmful Executive Orders and Actions," 90 FR 8237 (January 28, 2025).
[45] 87 FR 7624 (February 9, 2022).
[46] 88 FR 13956 (March 6, 2023).
[47] 88 FR 24854 (April 24, 2023).
[48] *Id.* at 24866.
[49] *Id.*

technology review[50] and focused on the identification of any developments in practices, processes, and control technologies that have occurred since the finalization of the 2012 MATS Rule and since publishing the 2020 Technology Review. Based on that review, the EPA concluded that revisions to certain standards were warranted and proposed three changes. First, the EPA proposed to revise the existing coal-fired EGU fPM emissions standard, which is a surrogate for non-Hg HAP metals, from 0.030 lb/MMBtu to 0.010 lb/MMBtu, and proposed corresponding reductions in the alternative emission standards for total and individual non-Hg HAP metals. Second, the EPA proposed to require that all coal- and oil-fired EGUs demonstrate compliance with the applicable fPM emission standard exclusively by using PM CEMS, and to remove the option of using alternative compliance demonstrations. Third, the EPA proposed to revise the Hg emission standard for lignite-fired EGUs from 4.0 lb/TBtu to 1.2 lb/TBtu with an alternative output-based standard of 0.013 lb/gigawatt-hour (GWh). All proposed changes were ultimately promulgated in the 2024 Final Rule.[51]

In the 2024 Final Rule, the EPA established a substantially more stringent fPM emission standard, which serves as a surrogate for the non-Hg HAP metals. The fPM standard was lowered from 0.030 lb/MMBtu to 0.010 lb/MMBtu for all existing coal-

[50] Described in Document ID No. EPA-HQ-OAR-2018-0794-0015.
[51] In the 2024 Final Rule, the EPA also removed paragraph (2) of the definition of "startup" in 40 CFR 63.10042. *See* 89 FR 38550 (May 7, 2024). The regulation now requires that all EGUs use the work practice standards in paragraph (1) of the definition of "startup" in 40 CFR 63.10042, which was already being used by virtually all affected EGUs. The EPA made this revision in response to *Chesapeake Climate Action Network v. EPA*, 952 F.3d 310 (D.C. Cir. 2020), in which the D.C. Circuit remanded the alternative "startup" work practice standard in paragraph (2) to the EPA for reconsideration. The compliance deadline for the changes to the "startup" definition was January 2, 2025. The EPA did not propose amendments to this aspect of the 2024 Final Rule and is not finalizing any changes to the "startup" definition at this time.

fired EGUs. The 2024 Final Rule also proportionally lowered the individual and total non-Hg HAP metal emission limits.

In the 2024 Final Rule, the EPA revised its conclusion in the 2020 Final Rule by finding that there were developments in practices, processes, and control technologies to reduce fPM emissions, that the costs to comply with the more stringent fPM standard based on these developments were reasonable, and in light of those considerations, that the revised standard was "necessary." The EPA stated that it had considered costs in several ways, including cost effectiveness, the total capital costs of proposed measures, annual costs, and costs compared to total revenues. In addition, in the 2024 Final Rule, the EPA found that most existing coal-fired EGUs had reporting fPM levels that were below the 2012 MATS Rule 0.030 lb/MMBtu emission limit and that costs were lower than estimated during promulgation of the 2012 MATS Rule fPM emission limit.[52]

E. Summary of the 2025 Proposed Repeal

On June 17, 2025, the EPA proposed to repeal the amendments to MATS in the 2024 Final Rule.[53] Based on our reevaluation of the 2024 Final Rule, we proposed to repeal the fPM emission standard for all existing coal-fired EGUs of 0.010 lb/MMBtu, the requirement for all coal- and oil-fired EGUs to demonstrate compliance with the fPM emission standard by using PM CEMS, and the Hg emission standard for lignite-fired EGUs of 1.2 lb/TBtu. The Agency proposed to find that the cost-effectiveness values associated with the revised fPM emission standard are significantly higher than cost-

[52] For instance, the EPA found at the time that the median fPM rate of the 296 coal-fired EGUs assessed in the 2024 Final Rule was 0.004 lb/MMBtu, or 60 percent below the revised fPM limit of 0.010 lb/MMBtu. *See* 89 FR 38522 (May 7, 2024).
[53] 90 FR 25535 (June 17, 2025).

effectiveness values that we previously rejected in other technology reviews and related actions under CAA section 112. The EPA also proposed to find that the requirement utilizing PM CEMS for compliance demonstration was an unnecessary expense for coal- and oil-fired EGUs and that the owners and operators of such sources should maintain the option to utilize other monitoring methods to demonstrate compliance with the fPM emission standard. Lastly, the EPA proposed to find that the Agency failed to demonstrate that the revised Hg emission standard for lignite-fired EGUs is achievable across the broad range of boiler types and varying compositions of the different lignite fuels. The Agency also took comment on whether we should consider the potential for meaningful risk reduction when weighing costs to determine if it is necessary to revise standards in a CAA section 112(d)(6) technology review.

III. Basis for Final Repeal of the 2024 Final Rule

In this section, the EPA describes what aspects of the proposal the Agency is finalizing, a summary of key comments and responses, and the rationale for each final decision. For all comments not discussed in this preamble, comment excerpts and the EPA's responses are available in the comment summary and response document entitled *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, Repeal of Amendments, Summary of Public Comments and Responses on Proposed Rule*, available in the docket for this rulemaking.[54]

Because this final rule repeals three requirements of the 2024 Final Rule—revisions to the emissions standards for fPM as a surrogate for non-Hg HAP metals for existing coal-fired EGUs, the fPM emission standard compliance demonstration

[54] Docket ID No. EPA-HQ-OAR-2018-0794.

requirements, and the Hg emission standard for lignite-fired EGUs—the EPA intends the repeal of each requirement to be severable from one another. Just as each requirement added in the 2024 Final Rule addressed distinct aspects of MATS and employed a distinct rationale, so also is the EPA finalizing the repeal of each requirement for separate and independent reasons. When the EPA adopted these three requirements in the 2024 Final Rule, the EPA explained that each of the three requirements were severable from each other as each is "multifaceted and addresses several distinct aspects of MATS for independent reasons."[55] By the same token, the repeal of each of requirement is severable from the repeal of the remaining requirements.

The EPA intends that the various components of this final rule operate independently of the other and be considered independently. For example, the EPA notes that our justifications for repealing the revised fPM standard as a surrogate for non-Hg HAP metals (and related revised standards for each non-Hg HAP metal) are rooted in the poor cost-effectiveness of the controls, while our justifications for repealing the requirements for lignite-fired EGUs to meet the same standard for Hg emissions as other coal- and oil-fired EGUs rest on a separate analysis specific to the variability of lignite-fired units and lack of sufficient data. Similarly, our justifications for repealing the changes to the fPM compliance demonstration requirement are based on the cost of CEMs and the determination that it is not necessary to make CEMS the exclusive means of demonstrating compliance to further transparency and informational values.

Each of these actions is independent from each other. In particular, the repeal of the revised emission standard for fPM as a surrogate for non-Hg HAP metals (and related

[55] 90 FR 38518 (May 7, 2024).

revised standards for each non-Hg HAP metal) and the repeal of the fPM compliance demonstration requirement to utilize PM CEMS are independent and based on separate rationales. While the EPA considered the technical feasibility of PM CEMS in establishing the revised fPM standard, the EPA finds there are independent reasons for repealing each requirement, as just noted. If the EPA were to repeal any one or two of the three requirements, but not the other one or two, each repeal would reinstate requirements from the 2012 MATS Rule that continue to be workable without the other one or two revisions in place.

Accordingly, the EPA finds that the repeal of each set of revised standards and requirements is severable from the repeal of the other revised standards and requirements. Thus, the EPA has independently considered and adopted each portion of this final rule, which includes the repeal of the revised fPM emission standard as a surrogate for non-Hg HAP metals (and related revised standards for each non-Hg HAP metal), the repeal of the fPM compliance demonstration requirement, and the repeal of the revised Hg emission standard for lignite-fired units, and each is severable should there be judicial review. If a court were to invalidate any one of these elements of the final rule, the EPA intends the remainder of this action to remain effective. Importantly, the EPA designed the different elements of this final rule to function sensibly and independently. Further, the supporting bases for each element of the final rule reflect the Agency's judgment that the element is independently justified and appropriate, and that each element can function independently even if one or more other parts of the rule has been set aside.

A. Filterable PM Emission Standard for Existing Coal-Fired EGUs

1. What is the EPA finalizing for the filterable PM emission standard for existing coal-

fired EGUs?

The EPA proposed repealing the lower fPM limit of 0.010 lb/MMBtu for existing coal-fired EGUs based on a determination that the cost of the revision to the standard are unreasonable, and thus, not "necessary" as required by CAA section 112(d)(6). The EPA also proposed to revert the corresponding total and individual HAP metal emission standards to the limits that were promulgated in the 2012 MATS Rule if the repeal of the more stringent fPM limit were finalized. The EPA solicited comment on whether the cost-effectiveness rationale used to justify the revised fPM emission standard is consistent with the Agency's prior CAA section 112(d)(6) technology review determinations (Question #1) and on whether there are other cost-effective and achievable alternative standards that the EPA should consider as an alternative to a standalone repeal of the 0.010 lb/MMBtu fPM emission standard (Question #2). The EPA also took comment on whether risk should be a factor that the Agency considers when conducting technology reviews and if so, how.

The EPA is finalizing its proposal to repeal the more stringent fPM emission standard and the corresponding total and individual non-Hg HAP metal standards that were promulgated in the 2024 Final Rule and to revert to the limits set in the 2012 MATS Rule, which reduce risk to acceptable levels and provide an ample margin of safety. Commenters provided both supportive and opposing arguments for issues regarding the fPM emission standard. Neither these comments nor the Agency's updated analyses altered the EPA's views of the conclusions proposed or required changes to the proposed regulatory language.

2. What is the rationale for the EPA's final decision to repeal the filterable PM standard

for existing coal-fired EGUs?

In this final rule, the EPA is repealing the lower fPM standard of 0.010 lb/MMBtu for existing coal-fired EGUs that the EPA established in the 2024 Final Rule, as well as the alternative total and individual non-Hg HAP metal limits and returning all of them to the emissions standards promulgated in the 2012 MATS Rule. As discussed in this section, the EPA determines upon further review that the cost-effectiveness of the revised standards is not reasonable and compares unfavorably to prior Agency decisions on cost-reasonableness across other technology reviews and other section 112 actions where costs are considered. In addition, after reviewing the comments the EPA received concerning the consideration of risk in the context of a CAA section 112(d)(6) review, the Agency concludes that the results of the residual risk review may be considered when evaluating whether revisions to the emission standards are cost-reasonable and therefore "necessary" under CAA section 112(d)(6). As explained further in section III.A of this preamble, the EPA finds that it is appropriate to consider the conclusions of the section 112(f)(2) risk review in all subsequent section 112(d)(6) reviews. For a risk review, the Agency determines the risk remaining from HAP emissions from every source in a source category, and the statute includes specific risk thresholds for remaining cancer risk. Specifically, the statute incorporates a rebuttable presumption that a cancer risk above 100 in 1 million is unacceptable[56] and establishes an aspirational goal of using standards

[56] *See* CAA section 112(f)(2)(B), 42 U.S.C. 7412(f)(2)(B) (preserving the EPA's approach in the Benzene NESHAP, under which cancer risk above 100 in 1 million is presumptively unacceptable unless the presumption is overcome on a category-specific basis).

to reduce cancer risk for each source in a category to no greater than one in one million.[57] The Agency finds that the results of the residual risk review can be considered in technical reviews going forward to inform the potential for meaningful risk reduction when evaluating cost.

In this case, the MACT standard for non-Hg HAP metals in the 2012 MATS Rule lowered the maximum individual lifetime cancer risk (cancer MIR) from such HAP metals to below one-in-one million for every coal-fired EGU in the country, thereby achieving the aspirational goal of CAA section 112(f)(2)(A). In such cases, the EPA now concludes that a greater emphasis on cost is warranted in light of the low potential for further risk reduction, and that additional controls would generally only be "necessary" when the costs are on the lower end of what has been found acceptable from a cost perspective in prior CAA section 112 actions. For emissions of non-Hg HAP metals from coal-fired EGUs, in light of the high cost of the controls, a common metric the EPA considers in CAA section 112(d)(6) technology reviews, and the low remaining risk of cancer from these emissions, the Agency concludes that the 2024 revisions are not necessary. The EPA views each of the rationales set out in this section—a change of views on cost reasonableness of the additional controls evaluated in the 2024 Final Rule and the additional consideration of the low remaining risk for this source category—as separate and independent bases for repeal, either one of which would lead the Agency to

[57] *See* CAA section 112(f)(2)(A), 42 U.S.C. 7412(f)(2)(A) (requiring the EPA to promulgate standards if the cancer risk to the most exposed individual exceeds one-in-one million eight years after the EPA established MACT standards for the source category.

conclude that the revised standards in the 2024 Final Rule were not "necessary" under CAA section 112(d)(6).

As the EPA noted in the 2024 Final Rule, the Agency considers costs in various ways depending on the rule and the affected sector. For example, the EPA has considered the cost effectiveness of controls in the vast majority of CAA section 112 rulemakings where costs are considered, and the Agency has also considered total capital costs of control measures, annual compliance costs, and the compliance costs compared to total revenues (*e.g.*, cost-to-revenue ratios). In the 2024 Final Rule and, by the same token, in this rule, the most important indicator of cost is cost effectiveness, which is the relationship of costs to emission reductions, because that indicator sheds the most light on whether the revised emissions standard that is based on those controls is "necessary" under CAA section 112(d)(6). As the EPA acknowledged in the 2024 Final Rule, the cost-effectiveness ratio of the revised 0.010 lb/MMBtu fPM standard was significantly higher than cost-effectiveness ratios the EPA rejected in past technology reviews conducted under CAA section 112(d)(6) for other source categories.[58] Moreover, the cost effectiveness values for the specific non-Hg HAP metals (*i.e.*, the metals for which fPM serves as a surrogate) emitted from EGUs are almost an order of magnitude higher than the highest values accepted for such HAP metals under CAA section 112(d)(6) reviews for other source categories. *See* section III.A.3 of this preamble, below, for a more detailed discussion. The EPA now finds that the costs for this source category to achieve the revised standard, in relation to the amount of emission reductions, are unreasonable,

[58] 89 FR 38533-34 (May 7, 2024). These rules are also noted in section III.A.3 of this preamble.

such that the revised standard is not “necessary” under CAA section 112(d)(6). As noted below, the EPA also finds that the limited risk posed by emissions from coal-fired power plants, coupled with the high cost-effectiveness values, are a separate and additional reason for its determination that the revised standard is not “necessary” under CAA section 112(d)(6).

In the 2024 Final Rule, the EPA estimated the cost effectiveness for EGUs that were reporting average fPM rates above the 0.010 lb/MMBtu fPM emission standard to be $10.5 million per ton of non-Hg HAP metals and $34,500 per ton of fPM (2019$). The EPA has since revised these cost effectiveness estimates based on updated expectations regarding the existing coal-fired EGU fleet, reflecting fewer planned retirements. Table 3 of this preamble summarizes the updated cost effectiveness of the more stringent fPM emission standard. For the purpose of estimating cost effectiveness, the analysis presented in this table is based on the observed emission rates of all existing coal-fired EGUs except those with retirements reported to the U.S. Energy Information Administration (EIA) via EIA Form 860.[59] The analysis presented in Table 3 estimated the costs associated for each unit to upgrade its existing PM controls to meet a fPM emission standard of 0.010 lb/MMBtu, using the same methodology as the 2024 Final

[59] This is described in detail in the 2023 Technical Memo, 2024 Technical Memo, and the *2025 Update to the 2024 Technology Review for the Coal- and Oil-Fired EGU Source Category* memorandum (“2025 Technical Memo”) available in the rulemaking docket (Docket ID No. EPA-HQ-OAR-2018-0794).

Rule. In the cases where existing PM controls would not achieve the necessary reductions, unit-specific FF installation costs were estimated.[60]

Based on this updated analysis, total annual costs are estimated to be approximately $93.7 million with a cost effectiveness of $11.1 million per ton of non-Hg HAP metals, and $36,502 per ton of fPM, for the 0.010 lb/MMBtu fPM emission standard, which is about 5 percent higher than the 2024 Final Rule estimated.

Table 3—Summary of Revised Cost Effectiveness Analysis for the Updated fPM Emission Limit (*i.e.*, 0.010 lb/MMBtu)

	2025 Final Repeal Rule
Number of Affected Units (Capacity, GW)	37 (16.8)
Annual Cost, ($M, 2019 dollars)	93.7
fPM Reductions (tpy)	2,567
Total Non-Hg HAP Metals Reductions (tpy)	8.4
Total Non-Hg HAP Metals Cost Effectiveness ($M/ton)	11.1
Total Non-Hg HAP Metals Cost Effectiveness ($/lb)	5,600

Upon reconsideration, the EPA is finalizing the repeal of the more stringent fPM standard and corresponding total and individual HAP metal standards promulgated in the 2024 Final Rule because the cost effectiveness of the revised standard is inconsistent with that of the EPA's prior technology review determinations. In the 2024 Final Rule, the EPA asserted that differences between the power sector and the other source categories subject to previous technology reviews justified accepting an unusually high cost-effectiveness ratio. Upon further review, the Agency no longer believes the unique nature

[60] Note that unlike the cost projections presented in the Regulatory Impact Analysis (RIA), the updated estimates do not account for the two-year compliance extensions for units listed on Annex 1 of the Presidential Proclamation or any future changes in the composition of the operational coal-fired EGU fleet that may occur by 2028 as a result of other factors affecting the power sector.

of the utility power industry supports the decision to revise the fPM standard for coal-fired EGU's.

In particular, the EPA stated in the 2024 Final Rule that the large size of the power sector relative to other industrial sectors meant that the amount of its emissions were relatively greater than other source categories.[61] The EPA added that the size of the sector also includes relatively large revenues, which the Agency believed at the time further justified the control costs.[62] The EPA also stated in the 2024 Final Rule that because of the emission rates already achieved by most of the coal-fired EGUs in the source category, the costs of complying with the revised standard would be borne by only some of the sources in the source category.[63] On that basis, the EPA asserted that the controls would not have "significant effects" on the industry, *i.e.*, the power sector.[64] Finally, the EPA claimed that the cost effectiveness of the controls should be considered in light of these characteristics of the source category, which distinguish it from other source categories that the EPA has regulated under CAA section 112.[65]

The EPA now believes that it was inappropriate to rely on the differences between the EGU sector and other sectors with respect to consideration of costs in the development of standards. The EPA has consistently maintained that the statute treats the EGU source category the same as all other major source categories with respect to regulation under CAA section 112(d) once the Agency decides pursuant to CAA section 112(n)(1)(A) to add the EGU source category to the list of regulated major sources under

[61] 90 FR 38524 (May 7, 2024).
[62] *Id.* at 38534.
[63] *Id.*
[64] *Id.* at 38524.
[65] *Id.*

CAA section 112(c)(1).[66] In the 2024 Final Rule, however, the Agency ignored that position and used certain unique factors about the power sector in an attempt justify otherwise unreasonable costs. Specifically, the Agency no longer believes it was reasonable to establish a fPM standard with one of the highest cost-effectiveness values ever accepted for fPM under CAA section 112(d)(6), particularly when the cost-effectiveness ratio for the actual non-Hg HAP metal emissions was approximately an order of magnitude higher than any cost-effectiveness value the Agency has ever found reasonable for non-Hg HAP metals. The longstanding use of fPM as a surrogate for non-Hg HAP metals does not excuse the Agency from considering cost-effectiveness as to the non-Hg HAP metals themselves. The purpose of CAA section 112 is to regulate HAP emissions, and when there exists a disparity in cost effectiveness between a surrogate and the associated HAP, it is important to give sufficient consideration to that disparity, but the Agency failed to do so in the 2024 Final Rule. Thus, although the Agency identified what it considered at the time to be "developments" in some control strategies in the 2024 Final Rule, the costs for the power sector to implement those developments are not reasonable, such that the revised standards are not "necessary" under CAA section 112(d)(6). As a result of this final rule, the fPM and corresponding total and individual non-Hg HAP metal emission standards will revert to the standards that were promulgated

[66] After the EPA makes the "appropriate and necessary" finding for the EGU source category required in CAA section 112(n)(1)(A), the EGU source category becomes included in the "list of all categories and subcategories of major sources" in CAA subsection 112(c)(1). 42 U.S.C. 7412(c)(1), (n)(1)(A). That listing, in turn, triggers the same, general regulatory requirements for the EGU source category as apply to the other listed source categories, under CAA section 112. *See, e.g.,* 42 U.S.C. 7412(c)(2); 88 FR 13956, 13960-61 (March 6, 2023) (recounting the EPA's position since 2000 that an affirmative "appropriate and necessary" finding puts the EGU source category in the same position as all source categories listed in CAA section 112(c)(1)).

in the 2012 MATS Rule (*e.g.*, 0.030 lb/MMBtu for fPM and associated prior standards for non-Hg HAP metals).

In addition to finding that the costs are unreasonable on their face, circumstances have changed materially since promulgation of the 2024 Final Rule. Fewer coal-fired EGUs are likely to retire instead of complying with MATS because of an increasing need for electricity generation, including to support growing demand from the technology sector. Moreover, Congress recently passed, and President Trump signed into law, new legislation that repealed, amended, or defunded relevant provisions of the Inflation Reduction Act (IRA), including tax credits for solar and wind generation that the EPA cited in the 2024 Final Rule to predict an "accelerated" transition away from coal- and oil-fired generation.[67] Coupled with the Executive Orders discussed earlier in this preamble that establish different policies and programs to promote power generation from this source category, the EPA's prior predictions about the future of the power sector and conclusion that the unique characteristics of the power sector support a finding that the additional controls are "necessary" are no longer accurate.[68] Instead, that unique

[67] *Compare* 89 FR 38534 (May 7, 2024) (citing Pub. L. 117-169 (2022)), *with* Pub. L. 119-21 (2025).

[68] The EPA further clarifies that statements in the 2024 Final Rule regarding planned EGU retirements "due to factors independent of the EPA's regulation" were overbroad and did not reflect a detailed, source-by-source analysis of the costs of regulation. *See, e.g.*, 89 FR 38524-25 (May 7, 2024). In several recent cases, the Supreme Court has vacated EPA rules for misusing statutory authority and failing to consider the costs of regulation. *See West Virginia v. EPA*, 597 U.S. 697 (2022) (vacating CAA section 111(d) standards for pursuing generation shifting in violation of the major questions doctrine); *Michigan*, 576 U.S. at 749-50 (faulting the EPA's decision to regulate EGUs under CAA section 112 for failing to account for an estimated $9.6 billion in annual compliance costs). Although trends in a source category can be relevant under CAA section 112(d)(6), the inherent difficulty in determining whether a planned retirement is independent of regulatory pressure cautions against making such an assumption for regulatory purposes absent more direct engagement with and analysis of each source.

character of the power sector and the increasing demand supports this repeal because any unnecessary downward pressure on the power industry at this time is not in the national interest or in the interest of consumers.

The EPA's decision to repeal these standards from the 2024 Final Rule is further supported by the low remaining cancer risk attributed to HAP emissions from this source category. As noted in section II.A.1 of this preamble and discussed in greater detail in section IV of this preamble, CAA section 112(d)(6) and relevant case law support considering additional factors beyond developments in technology when deciding whether revisions to existing standards are "necessary," including cost. Considering risk in the context of the first technology review would be duplicative of the one-time risk review requirement, which is conducted at the same time and which generally includes an ample-margin-of-safety analysis that takes the costs of controls into account. However, Congress did include risk benchmarks in CAA section 112(f), and considering those benchmarks in subsequent technology reviews is consistent with the broad scope of the term "necessary" and reasonable because that information is part of the overall CAA section 112 record for each source category. Specifically, CAA section 112(f)(2)(A) directs the EPA to "promulgate standards" if the cancer risk to the most exposed individual is greater than one-in-one million.[69] Additionally, CAA section 112(f)(2)(B) incorporates the Benzene NESHAP approach, which generally presumes that a cancer risk of greater than 1-in-10,000 is unacceptable unless such presumption is overcome.[70]

[69] 42 U.S.C. 7412(f)(2)(A).
[70] *Id.* 7412(f)(2)(B).

The decision to consider the low remaining risk in the prior residual risk assessment in assessing the need for additional standards in the second and subsequent CAA section 112(d)(6) reviews is consistent with the ordinary meaning of the term "necessary," which is "required," "compulsory," or "determined or produced by the previous condition of things."[71] CAA section 112(d)(6), by its terms, expressly requires the EPA to consider "developments in practices, processes, and control technologies" when determining whether it is "necessary" to revise existing section 112 standards (*e.g.*, standards based on the MACT floor, a beyond-the-floor level of control, or a risk review). The EPA also considers the costs of potential revisions even though CAA section 112(d)(6) does not explicitly reference cost. The D.C. Circuit has upheld that interpretation,[72] and it is consistent with the Supreme Court's interpretation of the term "appropriate and necessary" in another provision of CAA section 112.[73] As with costs, the EPA interprets CAA section 112(d)(6) to authorize the EPA to take the low remaining risk identified in the prior residual risk review into account even though the provision does not explicitly refer to health risks. When the Agency has previously determined that residual risk for a source category is consistent with Congress' risk-reduction goals, that relatively low risk is relevant to determining whether additional standards are "necessary" and, if so, which standards are "necessary." That follows from the overall purpose of CAA section 112, which is to promote public health by reducing the hazards presented by the emission of air toxics, and from Congress' decision to establish and adopt the particular risk thresholds in the statute described above.

[71] Webster's Ninth New Collegiate Dictionary 790 (1984).
[72] *Ass'n of Battery Recyclers*, 716 F.3d at 673-74.
[73] *Michigan*, 576 U.S. at 748-49.

This interpretation is consistent with how the EPA has interpreted “necessary” under CAA section 112(n)(1)(A) by taking into consideration health risks. The Supreme Court explained the provisions of CAA section 112(n)(1)(A), including their background and context, in *Michigan v. EPA*, as follows:

> [T]he Clean Air Act Amendments of 1990 subjected power plants to various regulatory requirements…. [T]hese requirements were expected to have the collateral effect of reducing power plants’ emissions of hazardous air pollutants, although the extent of the reduction was unclear. Congress directed the Agency to “perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by [power plants] of [hazardous air pollutants] after imposition of the requirements of this chapter.” If the Agency “finds ... regulation is appropriate and necessary after considering the results of the study,” it “shall regulate [power plants] under [CAA section 112].”[74]

The Court went on to explain, with approval, the EPA’s interpretation of “necessary,” which, as noted, takes into consideration health risks:

> In 2012, [the EPA] reaffirmed [its prior] appropriate-and-necessary finding…. The Agency found regulation “appropriate” because (1) power plants’ emissions of mercury and other hazardous air pollutants posed risks to human health and the environment and (2) controls were available to reduce these emissions. It found regulation “necessary” because the imposition of the Act’s other requirements did not eliminate these risks.[75]

Interpreting “necessary” to authorize consideration of the prior residual risk review in the way described in this preamble is also consistent with CAA section 112(d)(6)’s direction to revise “emission standards promulgated under this section.” Specifically, after the EPA conducts the mandatory section 112(f)(2) residual risk review, subsequent section 112(d)(6) technology reviews will include a review and potential revision of all section 112 standards.[76] Considering the findings of the prior risk review,

[74] *Michigan*, 576 U.S. at 748 (quoting 42 U.S.C. 7412(n)(1)(A)).
[75] *Id.* at 749 (citing 77 FR 9304, 9363 (February 16, 2012)).
[76] *Ass’n of Battery Recyclers*, 716 F.3d at 673.

which are part of the record before the Agency, during those technology reviews is reasonable and accounts for CAA section 112's purpose of protecting public health.

The approach that the EPA is taking in this rulemaking, *i.e.*, considering the low residual risk findings from the 2020 Residual Risk Review, marks a change from the Agency's stated approach in the 2024 Final Rule, in which the Agency declined to consider the health-risk findings from the 2020 Residual Risk Review as part of the technology review. Specifically, the EPA stated that it was "not compel[led]" to "consider[] risks as a factor" in technology reviews under CAA section 112(d)(6).[77] The EPA explained that the CAA section 112(d)(6) technology review and the section 112(f) residual risk determination were "independent" of each other, and that "a determination under section 112(f) of an ample margin of safety and no adverse environmental effects alone will [not] … cause us to determine that a revision is not necessary under CAA section 112(d)(6)."[78]

However, in the 2024 Final Rule, the EPA did not say that CAA section 112 precludes the Agency from considering risks in connection with a CAA section 112(d)(6) technology review. Moreover, the EPA acknowledged that in some prior section 112(d)(6) reviews, the Agency has considered risks.[79]

For all of these reasons, the EPA concludes that it is reasonable to consider the low remaining risks identified in a prior residual risk review—particularly where, as here,

[77] 89 FR 38525 (May 7, 2024).
[78] *Id.* (quotation marks omitted).
[79] *Id.* at 38525 & n.31 (*citing National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry*, 71 FR 76603, 76606 (December 21, 2006), and *Proposed Rules: National Emission Standards for Halogenated Solvent Cleaning*, 73 FR 62384, 62404 (October 20, 2008)).

such risks are consistent with the thresholds Congress set out or adopted by statute—when determining in a second and subsequent CAA section 112(d)(6) review whether additional standards are "necessary." For this rule, the Agency considered the 2020 Residual Risk Review of MATS in the manner and for the reasons described elsewhere in this final action.

Having concluded that CAA section 112(d)(6) allows the EPA to consider the results of an earlier CAA section 112(f)(2) residual risk review in subsequent technology reviews, we must determine how and to what extent the Agency may consider risk in determining whether revised standards are "necessary." As noted above, the clearest benchmark is in CAA section 112(f)(2)(A), which the EPA has long interpreted as requiring an ample-margin-of-safety analysis but not mandating that the Agency require additional reductions in HAP emissions after considering costs and other factors. The D.C. Circuit upheld this interpretation, describing the one-in-one million risk level as an "aspirational goal" of the statute for sources of HAP emissions and not as the level that every source category must achieve under CAA section 112(f)(2).[80]

The EPA thus concludes that the statutory benchmarks for risk provide relevant guidance on whether additional regulation is "necessary" under CAA section 112(d)(6). If the remaining risk found during a prior residual risk review is below the one-in-one million risk level, the EPA may place greater emphasis on costs of the new controls. Over the years of implementing CAA section 112, the EPA developed cost metrics for evaluating whether it is reasonable to consider a particular control to be "necessary," and

[80] *NRDC*, 529 F.3d at 1082 (rejecting the argument that risks must be reduced to the one-in-one million threshold).

the Agency uses those metrics when evaluating whether controls are reasonable in several CAA section 112 contexts (*e.g.*, beyond the floor (BTF), ample margin of safety, generally available control technologies (GACT)). The EPA also uses these metrics when determining whether additional controls are necessary under CAA section 112(d)(6) on the theory that if the costs of such controls are within the range of what had been found reasonable in one rule, then those same costs are potentially reasonable for other source categories. If additional controls cost more than the historical range, we generally conclude that such controls are unnecessary. The EPA maintains that this approach is appropriate when the CAA section 112(f)(2) risk analysis shows remaining risks above statutorily set benchmarks (*e.g.*, risks greater than one-in-one million) or where noncancer risk from the source category emissions exceed a level adequate to protect public health with an ample margin of safety. However, where the MACT standard lowers cancer risks to below the statutory one-in-one million cancer risk threshold, the EPA concludes that more emphasis may be placed on cost in determining whether additional controls are "necessary" under CAA section 112(d)(6) within the context of the statute as a whole.

The statute makes clear that CAA section 112(d)(6) technology reviews are required even when a CAA section 112(f)(2) residual risk review finds cancer risk is below the one-in-one million threshold, and additional controls may be "necessary" when ongoing reductions in HAP are possible at relatively low cost. In cases like MATS, however, the EPA maintains that the effectiveness of the original MACT standard at lowering risks should be given greater weight. As noted in the 2020 Final Rule, no coal-fired EGU facility posed a cancer risk greater than one-in-one million. In fact, the highest cancer risk from non-Hg HAP metals from a coal-fired EGU was 0.3-in-one million, and most coal-fired EGUs were assessed to pose considerably lower cancer risks from such HAP emissions.[81] Despite these facts, in the 2024 Final Rule, the EPA established CAA section 112(d)(6) standards for emissions of fPM and corresponding standards for emissions of non-Hg HAP metals though the cost-effectiveness values of such controls were the highest (or among the highest) of any CAA section 112(d)(6) standard the Agency has established.[82] We now conclude it was not "necessary" to establish a new high-cost benchmark for non-Hg HAP metals from EGUs because the MACT standards in the 2012 MATS Rule achieved the aspirational goal for cancer risks from such HAP emissions. Instead, in such situations, the EPA believes a harder look at costs should be conducted and additional controls will be considered unnecessary unless the costs of such controls are at the lower range of cost acceptability. Imposing costs that are below historically accepted levels will continue to satisfy the statutory goal of continuing to reduce HAP emissions without unreasonably burdening source categories that pose very low risks due to HAP emissions. In addition, as noted above, even if the EPA did not consider the low remaining risks from the 2012 MACT standards as determined in the 2020 Final Rule, the EPA would conclude that the costs of the 2024 standards are unacceptably high in light of their high cost-effectiveness values, such that the 2024 standards are not necessary.

3. What key comments did the EPA receive on the filterable PM emission standard for existing coal-fired EGUs and what are our responses?

[81] Document ID No. EPA-HQ-OAR-2018-0794-0070.
[82] 89 FR 38530-35 (May 7, 2024).

Comment: Some commenters agreed with the EPA's proposal that the costs for the power sector to achieve the more stringent fPM standard are too high and are inconsistent with other technology review determinations. In the 2024 Final Rule, the EPA estimated that the cost-effectiveness for the 0.010 lb/MMBtu fPM emission limit was $10.5 million per ton of non-Hg HAP metals and $34,500 per ton of fPM. Commenters stated that these costs are not reasonable when compared to other technology reviews, including those cited by the EPA in the proposed rule, that rejected controls as not cost-effective. These technology reviews included the Petroleum Refinery Sector technology review[83] ($10 million per ton of total non-Hg HAP metals reduced), the Integrated Iron and Steel Manufacturing Facilities technology review[84] ($7 million per ton of non-Hg HAP metals reduced), and the Taconite Iron Ore Processing RTR[85] ($16 million per ton of non-Hg HAP metals reduced). Furthermore, commenters noted that the EPA has rejected similar or even smaller cost-effectiveness values in other CAA section 112 rulemakings:

- In the Hazardous Waste Combustors NESHAP beyond-the-floor analysis,[86] the EPA declined to impose a more stringent dioxin/furan emission limit because of

[83] *Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards*, 80 FR 75178, 75201 (December 1, 2015).
[84] *National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Residual Risk and Technology Review*, 85 FR 42074, 42088 (July 13, 2020).
[85] *National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Residual Risk and Technology Review*, 85 FR 45476, 45483 (July 28, 2020).
[86] *National Emission Standards for Hazardous Air Pollutants: Final Standards for Hazardous Air Pollutants for Hazardous Waste Combustors (Phase I Final Replacement Standards and Phase II)*, 70 FR 59402, 59462 (October 12, 2005).

cost, finding \$2.5 million to \$4.9 million per gram toxicity equivalence of dioxin/furan removed.

- In the Shipbuilding and Ship Repair NESHAP RTR,[87] the EPA declined to revise the formaldehyde emission limit after finding that spray line reconfiguration would cost \$43,000 per ton of formaldehyde reduced.
- In the Pulp and Paper NESHAP RTR,[88] the EPA declined to update standards in the final rule[89] for controlling kraft condensates emissions that would cost \$1,000 per ton of HAP removed or \$4 million per year.

Additionally, commenters stated that the cost analysis for the 2024 Final Rule underestimates overall compliance costs, as the EPA failed to identify all sources that would need to make air pollution control device upgrade investments and to account for unit-level operational challenges that could increase compliance costs. For example, commenters cited declarations submitted as part of challenges to the 2024 Final Rule, which stated that compliance with the 0.010 lb/MMBtu fPM emission standard at the Colstrip facility would have cost over \$350 million, with more recent estimates of over \$500 million that incorporate more accurate wage rates, structural steel install rates, scaffolding costs, duct installation costs, and total delivery costs.[90] Commenters pointed to the 2025 Proposal and stated that industrywide cost-effectiveness was at minimum

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[87] *National Emission Standards for Hazardous Air Pollutants for Shipbuilding and Ship Repair (Surface Coating); National Emission Standards for Wood Furniture Manufacturing Operations*, 76 FR 72050, 72056 (November 21, 2011).
[88] *National Emission Standards for Hazardous Air Pollutants: Pulp and Paper Residual Risk and Technology Review*, 76 FR 81328, 81345 (December 27, 2011).
[89] *National Emission Standards for Hazardous Air Pollutants: Pulp and Paper Residual Risk and Technology Review*, 77 FR 55698, 55701 (September 11, 2012).
[90] Document ID No. EPA-HQ-OAR-2018-0794-7154.

$10.5 million per ton of non-Hg HAP metals controlled, but the largest costs were found predominantly at Colstrip which results in approximately $16 million per ton of non-Hg HAP metals reductions using the EPA's "underestimated" costs.

Other commenters argued that the EPA was wrong in proposing that the cost effectiveness of the 0.010 lb/MMBtu fPM emission standard (as estimated in the 2024 Final Rule) is too high. Commenters stated that the examples rejecting high cost-effectiveness values that the EPA provided in the 2025 Proposal are flawed and should not be relied upon. These commenters asserted that the RTR for the Integrated Iron and Steel NESHAP also estimated a fPM cost effectiveness of $160,000 per ton, well above the $35,000 per ton of fPM estimated for the 2024 Final Rule. Further, these commenters stated that if the cost per ton of any of the non-Hg HAP metals is reasonable, then the control costs should also be regarded as reasonable. These commenters stated that the EPA has previously accepted Hg cost effectiveness values of up to approximately $32,000 per pound, which is the equivalent of $64 million per ton reduced. Commenters noted that the rejected cost effectiveness values from the Petroleum Refinery NESHAP RTR ($10 million per ton) and Integrated Iron and Steel NESHAP ($7 million per ton) are at the low end of the accepted Hg cost-effectiveness value, highlighting that the EPA has approved higher dollar per ton values in the past. Lastly, commenters argued that the EPA ignored the 2024 Final Rule's explanation for why the Petroleum Refinery Sector and Integrated Iron and Steel Manufacturing Facilities reviews were not comparable,[91]

[91] In the 2024 Final Rule, the EPA noted that the 2020 Integrated Iron and Steel Manufacturing rulemaking source category only covered 11 facilities with 3 tons per year (tpy) of HAP and 120 tpy of PM reductions, compared to MATS, which affected 314 coal-fired EGUs with estimated reductions of 8.3 tpy HAP and 2,537 tpy of fPM. *See* 89 FR 38524 (May 7, 2024).

and that the Agency also ignored the 2024 Final Rule's comparison of cost-effectiveness values with the Ferroalloys Production source category, in which the EPA approved higher cost-effectiveness values for PM than those estimated in the 2024 Final Rule.

Other commenters stated that the cost effectiveness comparison for a single facility bearing the highest costs under the 2024 Final Rule is inappropriate and arbitrary, as the cost-effectiveness ratio across an entire sector is very different than the cost-effectiveness ratio of a single facility. Commenters argued that it is expected that some facilities would face higher costs than others for a given regulation given differences in air pollution control devices. The commenters stated that it is irrational for the EPA to imply that the highest-cost facility's cost-effectiveness ratio cannot exceed a ratio rejected for a fleetwide average.

Response: The EPA generally agrees with commenters that cost effectiveness (*i.e.,* the costs per unit of emissions reduction) is a metric that the Agency consistently considers, alongside other cost metrics, in CAA section 112 rulemakings where it can consider costs. The EPA also agrees that the Agency has the discretion in how it considers statutory factors, including costs, under CAA section 112(d)(6).[92] The Agency disagrees, however, that there is any particular threshold that renders a potential control technology cost-effective or not.[93]

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[92] *See, e.g.*, *Ass'n of Battery Recyclers*, 716 F.3d at 673-74 (allowing that the EPA may consider costs in conducting technology reviews under CAA section 112(d)(6)); *Nat'l Ass'n for Surface Finishing*, 795 F.3d at 11.
[93] *See*, *e.g.*, *National Emissions Standards for Hazardous Air Pollutants: Ferroalloys Production*, 80 FR 37366, 37381 (June 30, 2015) ("[I]t is important to note that there is no bright line for determining acceptable cost effectiveness for HAP metals. Each rulemaking is different, and various factors must be considered.").

The EPA disagrees with the commenters who sought to distinguish prior rules in which the EPA declined to revise standards for non-Hg HAP metals due to the high cost-effectiveness values of those standards. As noted above, the cost-effectiveness of the 2024 Final Rule's revised standards for non-Hg HAP metals is substantially less favorable than in any other rule the EPA has promulgated under CAA section 112(d)(6). In several rules under CAA section 112(d)(6), the EPA declined to revise standards for non-Hg metal HAPs on grounds that the cost-effectiveness values were in the millions of dollars per ton reduced, which are roughly comparable to the cost-effectiveness values in the 2024 Final Rule. As commenters point out, in some of those cases, the EPA also noted industry-specific reasons for declining to adopt the revised standards, but the key reason in those rules, as here, was the high cost-effectiveness values. In addition, the commenters point to multiple cost-effectiveness values that the EPA has accepted in past actions for Hg control that are significantly higher than the values that the agency is rejecting for control of non-Hg HAP metals, but the EPA considers those values inappropriate for determining cost effectiveness of non-Hg HAP metals.

The EPA disagrees with commenters who argued that the 2025 Proposal focused on costs to a single facility. Although the EPA pointed out at proposal that the units at the Colstrip facility accounted for almost half of the 2024 Final Action's total compliance costs, that was not the basis for the proposed repeal and it is not the rationale for this final action repealing the more stringent fPM standard. Rather, the rationale is the high cost-effectiveness values, especially when coupled with the limited risk, including from the Colstrip facility.

Comment: Some commenters argued that the EPA failed to adequately explain why it is “necessary” under CAA section 112(d)(6) to revert to the 2012 MATS Rule standards when the CAA requires that the Agency “take into account developments in practices, processes, and control technologies” that have occurred since the EPA promulgated the original 2012 MATS Rule.[94] Commenters further asserted that the EPA must explain why the 2012 emissions standards are the maximum achievable emissions standards given major developments in control technology since 2012, including reduced costs and improvements of existing control technologies, better practices for monitoring the operation of ESPs, and more durable filter bag materials for FF, which commenters asserted the EPA did not dispute in the proposed rule. Commenters stated the EPA chose to disregard these developments and that the Agency’s own analysis in the 2024 Final Rule showed that at least 93 percent of the industry is already attaining a 0.010 lb/MMBtu fPM emission standard.

Response: The EPA notes that it has authority to reconsider past decisions and to revise, replace, or repeal a decision to the extent permitted by law and supported by a reasoned explanation.[95] In this case, as in the 2024 Final Rule, the EPA did not conduct a new mandatory technology review but, instead, reviewed a prior technology review. The next technology review for this source category is due within 8 years of the prior review, which was finalized in 2020. The EPA further disagrees with these commenters to the

[94] *See* CAA section 112(d)(6), 42 U.S.C. 7412(d)(6) (requiring the Administrator to “review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under [section 112] no less often than every 8 years”).
[95] *See, e.g.*, *Fox Television Stations*, 556 U.S. at 515; *Motor Vehicle Mfrs. Ass’n*, 463 U.S. at 42.

extent they suggest that CAA section 112(d)(6) requires the Agency to select the maximum degree of emissions reductions in setting standards. The technology review under CAA section 112(d)(6) does not allow the Agency to recalculate the MACT floor for any currently regulated HAPs. Rather, CAA section 112(d)(2) provides that the EPA must require the maximum degree of reduction in emissions of HAP that the Administrator determines to be achievable, taking into consideration cost, non-air quality health and environmental impacts, and energy requirements, and CAA section 112(d)(3) prescribes specific requirements for calculating the MACT. The EPA's task under CAA section 112(d)(6) is not to recalculate a new, lower MACT, but to determine whether, taking into account developments in technology and other relevant information, it is "necessary" to revise the standards. Further, EPA regulated all HAP emitted from EGUs in 2012 so there are no gaps to fill.

In this instance, the EPA reevaluated the 2024 Final Rule and determined that a more stringent fPM emission standard is not "necessary," including because of cost-effectiveness estimates, in light of the Agency's 2020 Technology Review. In this action, the EPA updated its evaluation of fPM compliance data for the coal-fired fleet and associated costs of PM controls to achieve a lower standard; specifically, total annual costs are estimated to be approximately $93.7 million with a cost effectiveness of $11.1 million per ton of non-Hg HAP metals for the 0.010 lb/MMBtu fPM emission standard.[96] The EPA acknowledges the reduced costs and improvements of existing ESP and FF

[96] Updates and revisions to the 2024 Technical Memo are described in detail in the *2025 Update to the 2024 Technology Review for the Coal- and Oil-Fired EGU Source Category* memorandum ("2025 Technical Memo") available in the rulemaking docket (Docket ID No. EPA-HQ-OAR-2018-0794).

control technologies compared to estimates from the 2012 MATS Rule and acknowledges that the fleet is largely overperforming with the fPM emission standard, but that fact alone does not make the high cost-effectiveness number reasonable or necessary under section 112(d)(6), particularly in light of the low remaining risk.

Comment: Several commenters generally supportive of the proposal urged the EPA to acknowledge additional considerations for rejecting the 0.010 lb/MMBtu fPM emission standard. First, commenters stated that the 2024 Final Rule's reliance on "considering cost in various ways"—such as comparing them to typical capital and total expenditures for the power sector, total power sector sales, and total PM upgrade control costs and emissions of the fleet—to explain its acceptance of high cost-effectiveness values should be rejected. Commenters questioned the use of compliance costs compared to revenues, arguing that the EPA would be hard-pressed to find that the utility sector as a whole cannot afford the cost of virtually any regulatory action, especially when such action is viewed in isolation. Commenters argued that the framing of considering costs in various ways in the 2024 Final Rule departed from the EPA's longstanding precedent regarding cost consideration in an RTR.

Second, a commenter requested that the EPA also reject the 0.010 lb/MMBtu fPM emission standard because of a flawed technical analysis based on truncated and unrepresentative data. Commenters noted that, for many units, the EPA relied on only two quarters of data and failed to explain the reasoning behind the EPA's decision to not incorporate all compliance data. Commenters also said that the cost analysis should account for other indirect impacts on grid reliability, such as security risks associated with temporarily reduced electric generation capacity and lost revenues during the downtime required to engineer and retrofit additional control technologies required to comply with the 2024 Final Rule.

Alternatively, other commenters said that the EPA reasonably explained costs in the 2024 Final Rule and that the EPA's proposal to repeal the fPM emission standard based on high costs is arbitrary and capricious. These commenters argued that the EPA's view about what is cost-effective is subjective and has nothing to do with what can be achieved—considering costs or otherwise. Commenters stated that the EPA did not cite any example of cost being the sole factor supporting a decision to revise or not to revise standards, as it did in the proposed rule here.

Response: The EPA disagrees in part with commenters stating that the Agency does not consider costs in various ways in CAA section 112 rulemakings. As stated earlier in this preamble, the EPA routinely considers cost effectiveness metrics together with additional factors, such as other relevant cost metrics (*e.g.,* total costs, annual costs, and costs compared to revenues), and impacts to the regulated industry, to determine whether, taking into account developments in practices, processes, and control technologies, it is "necessary" to revise emissions standards pursuant to CAA section 112(d)(6). For example, in the 2015 Ferroalloys rulemaking, the EPA rejected a potential control option due to concerns about technical feasibility and the significant economic impacts the option would create for the industry, including potential facility closures that would impact significant portions of industry production.[97] The EPA agrees with these commenters, however, that the Agency's statements about the power sector in the 2024 Final Rule are not appropriate reasons to accept higher cost-effectiveness values relative

[97] 79 FR 60238, 60273 (October 6, 2014) (supplemental proposed rule).

to other source categories. As explained in section III.A.1 of this preamble, cost-effectiveness metrics are an important means of evaluating whether developments in technology make a revision "necessary" because they present the emission-reduction benefit relative to the cost of such emission reduction. Characteristics of the power sector such as number of units and quantity of emissions do not mean that metric is not reasonable, because the metric is already keyed to ton of HAP emissions reduced.

With respect to commenters' argument that the EPA's view about what is cost effective is subjective and therefore an improper basis for repealing the revised standards in the 2024 Final Rule, the EPA disagrees. Congress vested the EPA with authority to make judgments about when a revision is "necessary" under CAA section 112(d)(6), and cost-effectiveness metrics are an important input to the exercise of that reasoned judgment. To the extent that the EPA's view now differs from the view adopted in the 2024 Final Rule, the law is clear that the Agency has authority to reconsider, repeal, or revise past decisions to the extent permitted by law so long as the EPA provides a reasoned explanation.[98] Indeed, the position taken in the 2024 Final Rule was itself a departure from the conclusions reached in the 2020 Final Rule, as the Agency acknowledged at the time and asserted was permissible under the same legal doctrine supporting this reconsideration.[99] As noted in the 2024 Final Rule, the cost effectiveness ratio of the revised fPM standard for non-Hg metal HAPs was significantly higher than the cost-effectiveness ratios for those HAPs the EPA has rejected in the past in

[98] *See, e.g.*, *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 42 ("[R]egulatory agencies do not establish rules of conduct to last forever [and] an agency must be given latitude to adapt their rules and policies to . . . changing circumstances.").
[99] 89 FR 38513 (May 7, 2024).

technology reviews conducted under CAA section 112(d)(6) for other industries.[100] The cost effectiveness ratio of the revised fPM standard was also higher than cost-effectiveness ratios that the EPA accepted for fPM emissions in other industries in other CAA section 112(d)(6) reviews. The EPA now finds that the costs for the power sector to achieve the revised standard are too high, and, separately, certainly too high in light of the low remaining risks, such that the revised standard is not necessary under CAA section 112(d)(6).

B. Required Compliance Demonstration for the Filterable PM Standard

1. What is the EPA finalizing for the compliance demonstration requirements for the filterable PM standard?

The EPA proposed to repeal the requirement that sources must use PM CEMS exclusively for demonstrating compliance with the fPM emission standard, as well as the adjusted QA criteria,[101] and to return to the previous regulatory language from the 2012 MATS Rule and 2020 Final Rule that allowed owners and operators to demonstrate compliance using either quarterly stack testing, PM CPMS, or PM CEMS. The EPA solicited comment on the rationale that the higher costs for EGUs not currently utilizing PM CEMS, the availability of other air pollution control performance indicators that can inform operators of malfunctions, and the adequacy of current compliance options support repealing the requirement that all coal- and oil-fired EGUs must use PM CEMS

[100] *Id.* at 38533-34.

[101] Emission standards are used to determine the acceptable tolerance interval when correlating PM CEMS. In the 2024 Final Rule, the EPA instructed the use of 0.015 lb/MMBtu, instead of the finalized more stringent limit of 0.010 lb/MMBtu, when developing PM CEMS correlations to ease difficulties correlating PM CEMS. *See* 89 FR 38535 (May 7, 2024).

(Question #3). The EPA also proposed and solicited comment on reinstating the low emitting EGU (LEE) program for fPM and non-Hg HAP metals, which reduces the required stack testing frequency for sources that demonstrated that their emissions are less than 50 percent of the corresponding emissions limit for 3 consecutive years (Question #4). Lastly, the EPA proposed retaining the updated fPM measurement requirements of allowing either an increased minimum volume per run or the collection of a minimum mass per run.[102] The EPA solicited comment on these measurement requirements for fPM compliance demonstration, as the Agency believed retaining the additional option of sample mass would reduce measurement uncertainty and may reduce test durations and, therefore, reduce fPM testing costs (Question #5).

Commenters provided both supportive and opposing arguments regarding the EPA's proposed compliance demonstration requirements for fPM. With several minor, technical exceptions, comments received on the proposed repeal of the PM CEMS compliance demonstration requirement for fPM did not result in a change to the position the Agency set out in the proposed rule. Therefore, the EPA is repealing the requirement to use PM CEMS for compliance demonstration with the fPM emission standard and restoring flexibility to owners and operators to choose between the fPM compliance demonstration options as proposed. The EPA is also reinstating the LEE program for fPM and non-Hg HAP metals as proposed. The EPA received comments that supported retaining the flexibility of a minimum volume per run or minimum mass per run sampling

[102] For coal- and solid oil-fired EGUs, the 2024 Final Rule required a minimum catch for fPM of 6.0 mg or a minimum sample volume of 4 dry standard cubic meters (dscm) per run. Requirements for IGCCs included a minimum catch for fPM of 3 mg or a minimum sample volume of 2 dscm. There were no changes to the minimum catch and sample volume requirements for oil-fired EGUs.

requirements but argued that the updated minimum volume per run sampling requirement would result in longer test runs and impose significant burdens on operators. Based on these comments, along with an additional review of the accuracy of PM CEMS at low levels, the EPA is finalizing as proposed but with minor technical revisions to the sampling requirements based on the purpose of the fPM testing. If PM CEMS are used for the compliance demonstration, owners and operators are required to follow the updated sampling requirements for minimum volume per run or minimum mass per run, as proposed in the 2025 Proposal. For all other compliance demonstration options, owners and operators are required to collect a lower minimum sample volume as originally required in the 2012 MATS Rule.

2. What is the rationale for the EPA's final approach and decisions on the compliance demonstration requirements for the filterable PM standard?

Upon further review, the EPA concludes that mandating the use of PM CEMS and removing previously available compliance alternatives was not "necessary" pursuant to CAA section 112(d)(6). As discussed in section III.A of this preamble, the EPA is finalizing the proposed repeal of the more stringent fPM emission standard from the 2024 Final Rule and returning to the fPM emission standard set in the 2012 MATS Rule and reaffirmed in the 2020 Final Rule. Therefore, the EPA's conclusion in the 2024 Final Rule that the costs for PM CEMS are commensurate with the costs for stack testing[103] no longer applies, because longer duration runs that increase stack testing costs are no longer necessary to demonstrate compliance with a lower fPM. Many sources also use the stack testing compliance option to efficiently merge their PM and HCl testing programs into a

[103] 89 FR 38535-37 (May 7, 2024).

single testing mobilization to test for those pollutants in conjunction, possibly yielding further cost savings. Further, the Agency finds that although the 2024 Final Rule invoked CAA section 114(a)(1)(C) as offering additional authority for the PM CEMS requirement,[104] the provision is equally applicable to the alternative compliance demonstration options restored in this final rule.[105]

The 2024 Final Rule requirement to use PM CEMS to demonstrate compliance meant that up to two-thirds of EGU owners and operators would face higher compliance costs than when allowed to use quarterly stack testing or PM CPMS. As shown in more detail in the RIA for this final rule, the EPA estimates a cost savings of $2.9 million per year related to the repeal of the PM CEMS requirement, after the two-year exemption period (2030 to 2037); the estimated cost savings during the two-year exemption period (2028 to 2029) is $1.2 million per year. While the EPA concluded in the 2024 Final Rule that the use of PM CEMS would allow for more efficient pollutant abatement and increased transparency of EGU emissions,[106] the Agency no longer believes that those advantages outweigh the increased cost of PM CEMS compared to the two other compliance options (*i.e.,* PM CPMS and quarterly stack testing) that were determined to be appropriate for demonstrating compliance with the fPM emission standard in the 2012 MATS Rule.

[104] *Id.* at 38535.
[105] *See* CAA section 114(a)(1), (a)(1)(C)-(D), 42 U.S.C. 7414(a)(1), (a)(1)(C)-(D) (authorizing the EPA to require source owners or operators to “install, use and maintain such monitoring equipment, and use such audit procedures, or methods” and “sample such emissions” as required by the Administrator).
[106] 89 FR 38535 (May 7, 2024).

The EPA noted in the 2024 Final Rule that CEMS enable power plant operators to quickly identify and correct problems with air pollution control devices.[107] However, there are other ways that owners and operators can become aware of air pollution control malfunctions without employing PM CEMS. For example, operators at EGUs with an ESP can instantaneously track and record opacity, secondary corona power, secondary voltage (*i.e.,* the voltage across the electrodes), secondary current (*i.e.,* the current to the electrodes), spark rate, and alarm and fault indicators to ensure proper functionality of the ESP in real time. For EGUs with technology such as FFs, bag leak detection systems (BLDS) and parameters like pressure differential (*i.e.,* pressure drop), inlet temperature, temperature differential, exhaust gas flow rate, cleaning mechanism and cycle operation, and fan current and speed can serve as reliable indicators of process operations. These indicators also provide valuable data for analyzing trends and making informed decisions about operational improvements and investments. As noted earlier in this preamble and in the 2024 Final Rule, a large majority of sources are already reporting measured compliance data showing fPM emissions that are below the previous fPM standard of 0.030 lb/MMBtu (via either PM CEMS or the stack testing compliance option), which further illustrates that the various options for demonstrating compliance with the fPM standards have been appropriate and effective.[108]

Therefore, the EPA is repealing the requirement to use PM CEMS for demonstrating compliance with the fPM emission standard, as well as the adjusted QA

[107] *Id.* at 38536.
[108] Additionally, all fPM compliance data can be accessed by the public via the EPA's Web Factor Information Retrieval System (WebFIRE) at *https://cfpub.epa.gov/webfire*, which maintains the availability and transparency of fPM emissions.

criteria,[109] and returning to the previous requirement that allowed owners and operators to demonstrate compliance using quarterly stack testing, PM CPMS, or PM CEMS. This provides greater flexibility to owners and operators and reduces the compliance burden, while still assuring compliance with the fPM emission standard.

The EPA is also reinstating the LEE program for fPM and non-Hg HAP metals, which reduces the stack testing frequency for sources that have demonstrated that their emissions are less than 50 percent of the applicable emission limit for 3 consecutive years. Sources that had previously demonstrated that they qualify for LEE status would not have to re-demonstrate that qualification. In the 2024 Final Rule, the EPA found that the optional LEE program was "superfluous" due to the PM CEMS requirement and the revised fPM emission standard.[110] However, as the EPA is repealing those requirements, reinstating the LEE program for fPM and non-Hg HAP metals will further reduce the costs associated with stack testing for sources that opt in, while still assuring compliance with the emission standard.[111] As mentioned earlier in this section, since LEE testing is only required once every 3 years once a source has attained LEE status, the ongoing LEE

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[109] New PM CEMS installations must follow Performance Specification 11 (PS-11), which requires the development of a site-specific correlation curve to relate PM CEMS readings to the PM reference method values. Emission standards are used to determine the acceptable tolerance interval when correlating PM CEMS. In the 2024 Final Rule, the EPA instructed the use of 0.015 lb/MMBtu, instead of the finalized more stringent limit of 0.010 lb/MMBtu, when developing PM CEMS correlations to ease difficulties correlating PM CEMS. *See* 89 FR 38535 (May 7, 2024).

[110] 89 FR 38510 (May 7, 2024).

[111] The LEE provisions are designed to ensure emissions are minimized. For example, EGUs equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device are not allowed to pursue the LEE option under 40 CFR 63.10000(c). Furthermore, under 40 CFR 63.10000(c)(1)(i)(D), EGUs claiming LEE status may bypass a control device during emergency periods for no more than 2 percent of the EGU's annual operating hours.

testing program is approximately 8 to 10 percent of the cost of a quarterly stack testing program.

Finally, the EPA is also updating the fPM measurement requirements that allow either an increased minimum volume per run or the collection of a minimum mass per run. As stated in section III.A of this preamble, a large majority of sources have reported measured compliance data showing fPM emissions below the 0.030 lb/MMBtu fPM standard. It is important that a sufficient quantity (*i.e.*, mg of mass) of fPM be collected during these fPM test runs to allow for the accurate measurement of PM emissions, especially when the testing is being conducted to correlate or certify a PM CEMS. For these reasons, we have modified the fPM testing requirement to collect either a minimum catch of 6.0 mg or a minimum sample volume of 4 dscm per run if using a PM CEMS for compliance, whereas all other compliance demonstration options will be required to collect a minimum sample volume of 1 dscm per PM test run.

3. What key comments did the EPA receive on the compliance demonstration requirements for the filterable PM standard and what are our responses?

Comment: Some commenters agreed that there are other air pollution control indicators such as opacity, ESP power, and baghouse differential pressure that are used to provide timely information on potential equipment performance issues or malfunctions. Additionally, commenters said that the PM CEMS requirement falsely assumed the data would provide a better indicator of control equipment performance, which may not always be the case since PM CEMS measurements can be influenced by a variety of factors. Commenters stated that sources are required to comply with limits at all times, including between performance tests, and that under 40 CFR 63.10000(b), EGUs “must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions."

Commenters also stated that owners and operators have multiple tools beyond CEMS to identify malfunctions in air pollution control equipment. These commenters agreed with the EPA's explanation in the proposed rule that facilities equipped with ESPs can monitor parameters such as opacity levels which can indicate higher than normal levels of particulates in the exhaust gas; secondary corona power, secondary voltage, and secondary current (indicating the collection of particulates on the plates and wires) to verify proper operation; power levels to the rappers and vibrators (used to clean the plates and wires); and the continued operation of the ash removal system to prevent system backup. For units with FFs, commenters stated that operators can rely on, as indicators of control performance, BLDS; pressure differential (indicates a bag leak or excessive buildup of the ash layer on the filters); temperature differential (for optimal bag/filter conditions); exhaust gas flow rate to detect unfiltered gas escaping the system; power levels and operations of the bag vibrators or reverse-air systems to ensure proper bag cleaning activity; fan current which can indicate plugged bags; and opacity monitors. According to commenters, these monitoring practices, which are already in use across the industry, provide meaningful and timely insight into equipment condition and emissions performance without necessitating continuous emissions data. Additionally, other commenters stated that there are sufficient compliance indicators in place to ensure that PM (and HCl) emissions remain low between stack tests, such as operation of scrubber technology.

Alternatively, other commenters argued the EPA did not provide evidence that other parameters can be a substitute for complying with the fPM limit or be used in ways to quickly identify problems with pollution controls. Commenters also stated that the EPA did not demonstrate that these alternative parameters will provide the same or similar benefits as PM CEMS. Commenters disagreed that other performance indicators are as reliable as PM CEMS to identify malfunctions with the same sensitivity and that there is no requirement to continuously monitor and maintain a record of each of these parameters. Further, commenters argued that while monitoring of operational parameters of control technologies may reveal anomalous conditions broadly, it does not quantify the mass or concentration of increased fPM emissions.

Response: The EPA agrees that there are reliable performance indicators that are continuously monitored and recorded, which are used to provide timely information on potential equipment performance and control device issues or malfunctions. As discussed in section III.B of this preamble, the EPA noted in the 2024 Final Rule that PM CEMS enable power plant operators to quickly identify and correct problems with air pollution control devices.[112] However, there are other ways that owners and operators become aware of air pollution control malfunctions without employing PM CEMS. For example, for proper process operations purposes of the unit, operators of EGUs with an ESP can instantaneously track and record opacity, secondary corona power, secondary voltage (*i.e.*, the voltage across the electrodes), secondary current (*i.e.*, the current to the electrodes), spark rate, and alarm and fault indicators to ensure proper functionality of the ESP in real time. Similarly, for EGUs with technology such as FFs, BLDS and

[112] 89 FR 38536 (May 7, 2024).

parameters like pressure differential (*i.e.*, pressure drop), inlet temperature, temperature differential, exhaust gas flow rate, cleaning mechanism and cycle operation, and fan current and speed can serve as reliable indicators of process operations. These indicators, which are routinely monitored and recorded regardless of any regulatory requirement, also provide valuable data for analyzing trends and making informed decisions about operational improvements and investments. Moreover, these indicators help ensure that EGUs are operated and maintained, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. As noted earlier in this preamble and in the 2024 Final Rule, a large majority of sources are already reporting measured compliance data showing fPM emissions well below the previous fPM standard of 0.030 lb/MMBtu (either via PM CEMS or the stack testing compliance option), which further illustrates that the various options for demonstrating compliance with the fPM standards have been appropriate and effective.

Comment: Commenters agreed with the EPA that the costs of installing PM CEMS are significant and the 2024 Final Rule failed to articulate why such costs were justified as compared to the other compliance methods permitted since 2012. Commenters argued that the EPA did not consider the fact that certain CEMS technologies, based on their designs and models, might not have replacement parts readily available from the original equipment manufacturers; therefore, when a critical component of the CEMS breaks or needs replacement, repairs could require costly expenditures or even a total replacement of the CEMS. Commenters also provided examples of how stack testing or CPMS costs could be much less than the cost of PM

CEMS. For instance, commenters said that some sources conduct quarterly testing for HCl along with fPM to reduce stack testing costs further by merging the HCl testing and fPM testing into the same testing program mobilization, which would be noticeably cheaper than testing for HCl and fPM separately. Commenters also noted that testing costs for EGUs that previously qualified for PM LEE status were much less than the cost of PM CEMS, by some estimates as much as 20 to 30 times lower. Lastly, commenters explained that CPMS provide lower testing costs, simpler procedures for establishing operating limits, and fewer operational burdens compared to PM CEMS.

Other commenters disagreed that the higher costs of PM CEMS justify repealing the PM-CEMS-only compliance demonstration requirement from the 2024 Final Rule. Further, commenters said that the benefits of reduced pollution through the use of PM CEMS would exceed the minor incremental cost between PM CEMS and stack testing.

Response: As discussed in section III.A of this preamble, the EPA is finalizing the repeal of the more stringent fPM emission standard. The more stringent fPM standard required longer duration runs, which would increase the relative costs of stack testing. Therefore, the EPA's conclusion in the 2024 Final Rule that the costs for PM CEMS are commensurate with the costs for stack testing no longer applies because stack testing costs are not increasing due to longer duration runs.

However, the EPA disagrees that sources that elect to conduct quarterly testing for HCl tests combined with fPM would greatly reduce stack testing costs. On the contrary, adding HCl testing to an fPM testing program (or adding fPM testing to an HCl testing program) would result in an increased cost for testing, as opposed to lowering the cost. While some cost savings would be realized by efficiently "merging" a fPM and HCl testing programs into a single testing mobilization to test for those pollutants in conjunction, this approach would not result in a lower cost than what would be realized if testing for PM only.[113] Nevertheless, the EPA understands that testing for fPM and HCl would not double the cost of an "fPM only" test program, since the fPM and HCl testing would occur concurrently without needing separate testing mobilizations, equipment setups, and equipment tear downs.

The EPA agrees that testing costs for EGUs that previously qualified for PM LEE status will be much lower than the cost of PM CEMS, yielding further cost savings. Since LEE testing is only required once every 3 years once a source has attained LEE status, the EPA estimates that an ongoing LEE testing program is approximately 8 to 10 percent of the cost of a quarterly stack testing program.[114]

Comment: Some commenters argued that the EPA failed to adequately explain its changed view of PM CEMS in terms of superior accuracy, transparency, and pollution reduction afforded by using PM CEMS, asserting that PM CEMS are already widely used throughout the industry and that the costs are small compared to a facility's overall operating expenses. These commenters stated that the EPA did not demonstrate that the other compliance demonstration options will provide the same or similar benefits as PM CEMS. Commenters asserted that PM CEMS have the benefits of greater reliability and

[113] Commenters claim that quarterly stack testing for fPM costs $57,100/year, while merging the fPM testing with the HCl testing into the same testing mobilization would lower the testing costs to $37,500/year, yielding almost $20,000/year in cost savings. The EPA disagrees that costs for merging the stack testing for fPM and HCl would be lower than testing for fPM only.
[114] Per 40 CFR 63.10000(c)(1)(iii), an ongoing LEE PM testing program is required at least once every 36 months (or at 1/12th the frequency (*i.e.*, 8.3 percent)) of a quarterly PM testing program to demonstrate continued LEE status.

accuracy and that continuous monitoring allows rapid detection of pollution problems so violations can be prevented or quickly fixed. Commenters also asserted that real-time information on pollution has more operational relevance for plant managers than do stack tests because real-time CEMS data allow managers to find the reasons for problems and provide learning that can have significant long-term benefits. Specifically, commenters stated that in the 2024 Final Rule, the EPA found that requiring the use of PM CEMS would provide 35,040 15-minute values for each EGU during a 1-year period, which is 243 times more information than is provided by quarterly stack testing under the 2012 MATS Rule. Commenters also asserted that continuous monitoring can reveal wide variability that is obscured with stack tests that occur once a quarter, once a year, or even less frequently; and that continuous monitoring allows an automated response that can fix the problem before noncompliance occurs, or an alarm that notifies relevant personnel that a problem is occurring. Commenters also asserted that continuous monitoring is also a deterrent to negligence and fraud; when companies know that increases in pollution can be detected in real time, they are less likely to engage in risky or prohibited practices. Commenters also asserted that CEMS monitoring data allows the facility, neighbors, and regulatory entities to see if the facility is complying with the standard, as it does not rely on an outdated monitoring method and assumption that emissions will consistently remain at the level found during an unreliable stack test.

Further, commenters asserted that State regulatory programs rely on PM CEMS data to effectively limit emissions. For example, the Illinois Control Board recently relied on PM CEMS data in promulgating emissions limits for industrial facilities, including coal-fired power plants, during period of "start-up, malfunction, or breakdown."

Commenters said that this analysis would have been difficult to perform if only stack testing data were available, which would not comprehensively capture emissions levels during atypical startup, malfunction, or breakdown periods.

Response: The EPA recognizes that PM CEMS may have certain advantages over periodic stack testing in some situations. However, as discussed in section III.B of this preamble, pursuant to CAA section 112(d)(6), the EPA must consider cost in deciding whether it is "necessary" to revise the requirements and has broad discretion in selecting reasonable compliance demonstration methods under CAA section 112 and 114(a)(1). Stack testing under MATS has been shown to be less costly than operating and maintaining a PM CEMS on an annualized cost basis.[115] Moreover, sources subject to both an applicable PM and HCl standard under MATS may use the stack testing compliance option to efficiently merge their PM and HCl testing programs into a single testing mobilization to test for those pollutants concurrently, possibly yielding further cost savings. The EPA also notes that stack testing for fPM under MATS continues to be required on a quarterly basis, which is more frequent than typical stack test programs which are required at either annual or multi-year frequencies.[116] Finally, there is no

[115] Memo from Barrett Parker, EPA to Docket ID No: EPA-HQ-OAR-2018-0794, "*Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs*" (December 21, 2023).
[116] For example, industrial boilers subject to 40 CFR part 63, subpart DDDDD, are required to perform fPM testing on either an annual or 3-year frequency, depending on the PM emission rate during testing. For stationary reciprocating internal combustion engines subject to 40 CFR part 63, subpart ZZZZ, testing for carbon monoxide (CO) is required every 8,760 hours or 3 years, whichever comes first. For stationary combustion turbines subject to 40 CFR part 63, subpart YYYY, testing for formaldehyde is required on an annual basis. However, testing for fPM is not required for stationary combustion turbines under 40 CFR part 63, subpart YYYY, or 40 CFR part 630, subpart KKKK, and is instead at the discretion of the delegated authority.

indication in the record that EGUs are in noncompliance with the fPM standard. The record demonstrates consistent overperformance of the standard by a large percentage of the regulated community. In light of this, it is reasonable to continue to provide flexibility, and it renders the additional cost of mandating PM CEMS unnecessary.

Comment: Regarding stack testing for fPM, commenters generally agreed with the EPA's proposal to retain the option of allowing either an increased minimum volume per run or the collection of a minimum mass per run, since that option would provide owners and operators greater flexibility that may reduce measurement uncertainty, lower test durations, and therefore lower the fPM stack testing costs. However, commenters requested that the proposed updated minimum volume per run of 4 dscm should instead return to the 1 dscm level of the 2012 MATS Rule. Commenters said that a 4 dscm minimum volume per run for all compliance demonstration options would require longer duration stack test runs of approximately 9 hours, posing larger costs, emissions, and operational difficulties for units.

Further, commenters argued that if the EPA finalized the repeal of the more stringent fPM limit and the PM-CEMS-only compliance demonstration requirement, the increase to 4 dscm minimum volume for each fPM stack testing run would no longer be prudent for all compliance demonstration purposes. While commenters stated that higher sample volumes could be useful to reduce measurement uncertainty for sources operating near emission limits or with low-level test measurements, individual owners and operators are best able to make such decisions based on the unit-specific compliance strategies. Commenters who disagreed with the EPA's proposal to retain these updated sampling requirements argued that more mass or volume does not create a more accurate correlation with PM CEMS, as the overall shape of the correlation curve is defined by mid- and high- level test conditions that have sufficient fPM mass due to artificially detuned conditions. A few commenters asserted that a minimum mass option is not feasible, as the amount of PM mass collected on the filter during stack testing is not known until after the run is completed and the filters are dried and weighed. While historical test results should enable sources to reasonably estimate the mass that will be collected during each fPM stack test run, commenters argued that sources should not be required to repeat test runs based solely on the collection of less mass than expected.

Other commenters argued that the updates to the sampling requirements in the 2024 Final Rule are necessary to ensure reliable test results, particularly at the low levels of fPM many EGUs are measuring. However, commenters expressed concern that the updates to the sampling requirements combined with the repeal of the more stringent fPM emission limit could result in emission spikes during stack testing. Commenters argued that the lower fPM emission standard combined with the sampling requirements in the 2024 Final Rule would have required plants to maintain the low emission rates they have been demonstrating and better protect surrounding communities.

Response: The EPA agrees that sampling requirements that allow either an increased minimum volume per run or the collection of a minimum mass per run would provide EGU owners and operators greater flexibility. The EPA also recognizes that a 4 dscm minimum volume per run would require longer duration stack test runs and that those longer test runs are not necessary for all fPM compliance demonstration options.

However, the EPA disagrees with the assertion that more mass or volume does not create a more accurate correlation with PM CEMS. While the mid- and high-level test conditions during PM CEMS correlations or verifications will most likely use the minimum catch value of 6.0 milligrams (mg) per run, it is still necessary to accurately measure values for the low-level test conditions. The EPA agrees with commenters that historical test data provides sources with a reasonable indicator and estimate of the potential mass that would be collected during each test run, therefore making it unnecessary to utilize the minimum volume requirement, especially at the mid- and high-level test conditions.

After considering comments, and because the EPA is finalizing the repeal of the PM CEMS requirement and again allowing other fPM compliance demonstration options, the EPA is also finalizing minor technical revisions to the fPM sampling requirements. Specifically, the EPA is finalizing the requirement that allows EGU owners and operators using PM CEMS for compliance to collect either a minimum catch of 6.0 mg or a minimum sample volume of 4 dscm per run, in order to provide additional testing flexibility while also ensuring that a sufficient PM CEMS correlation sample is obtained. For EGU owners and operators using any other compliance demonstration option, the EPA is finalizing the revised minimum sample volume of 1 dscm per PM test run, which is considered sufficient for a representative gravimetric assessment of a source's PM compliance status.[117]

[117] More specifically, the 4 dscm sample volume (or 6.0 mg sample catch) requirement would apply to any test associated with PM CEMS testing (*e.g.*, Performance Specification 11 (PS-11) correlation curves, relative response audits (RRAs), and response correlation audits (RCAs)), whereas the 1 dscm sample volume requirement would apply to quarterly PM compliance testing. PM LEE testing programs would also be based upon the 1 dscm sample volume requirement, yet the required minimum sample volume for LEE testing will continue to be increased nominally by a factor of 2 (*i.e.*, at least 2 dscm), per 40 CFR part 63, subpart UUUUU, table 2.

C. Hg Emission Standard for Lignite-Fired EGUs

1. What are we finalizing as the Hg emission standard for lignite-fired EGUs?

In the proposed rule, the EPA proposed to repeal the Hg standard for lignite-fired EGUs in the 2024 Final Rule and to return to the 4.0 lb/TBtu emission standard promulgated in the 2012 MATS Rule and retained in the 2020 Final Rule. The EPA solicited comment on whether there is sufficient data demonstrating that the standard can be met by lignite-fired EGUs with a range of boiler types and variable fuel composition (Question #6). The EPA also solicited comment on other achievable and cost-effective Hg standards for lignite-fired EGUs that are based on developments in practices, processes, and control technologies that the EPA should consider as an alternative to a standalone repeal of the 1.2 lb/TBtu standard (Question #7).

Upon further consideration and after reviewing comments received, the EPA is repealing the 1.2 lb/TBtu Hg limit for lignite-fired EGUs that was promulgated in the 2024 Final Rule and reverting to the 4.0 lb/TBtu Hg limit that was set in the 2012 MATS Rule and retained in the 2020 Final Rule.

2. What s the rationale for our final approach and decisions on the Hg emission standard for lignite-fired EGUs?

In the 2012 MATS Rule, the EPA promulgated a beyond-the-floor standard for Hg for the subcategory of existing coal-fired units designed for “low rank” virgin coal (*i.e.*, lignite) based on the use of ACI for Hg control.[118] The EPA established a Hg emission standard of 4.0 lb/TBtu for lignite-fired utility boilers and 1.2 lb/TBtu for utility

[118] 77 FR 9304 (February 16, 2012).

boilers firing all other types of coal (*e.g.*, anthracitic coal, bituminous coal, subbituminous coal, and coal refuse).

The 2024 Final Rule lowered the Hg standard for lignite-fired EGUs from 4.0 lb/TBtu to 1.2 lb/TBtu based on the EPA's determination that commercially available control technologies and improved methods of operation would allow lignite-fired EGUs to meet a more stringent emission standard. The more stringent Hg emission standard brought the requirement for lignite-fired EGUs in line with the emission limitation requirements of EGUs firing all other types of coal. In the 2024 Final Rule, the EPA reviewed coal composition information and concluded that the Hg content, the halogen content, and the alkalinity were similar between various lignite and subbituminous coals. In 2021, EGUs firing subbituminous coal emitted Hg at an average annual rate of 0.6 lb Hg/TBtu with measured values as low as 0.1 lb/TBtu, which the Agency found demonstrated that EGUs burning subbituminous coal have utilized control options to meet the 1.2 lb/TBtu emission standard despite the challenges presented by the low halogen content in the coal (which results in difficult-to-control elemental Hg vapor in the flue gas stream).[119] The Agency asserted that its cost-effectiveness estimates for a model 800 MW lignite-fired EGU using a range of sorbent injection rates to meet the revised Hg emission standard were lower or consistent with cost-effectiveness values for Hg controls that the EPA has found to be acceptable in previous rulemakings.

After reviewing the revised emission standard that was promulgated in the 2024 Final Rule, the EPA is repealing the revised Hg emission limit for lignite-fired EGUs because the revised standard was based on insufficient data to demonstrate that lignite

[119] 88 FR 24880 (April 23, 2023).

units can meet the lower limit over the range of boiler types and variable compositions of fuels used at lignite-fired EGUs. Commenters provided both supportive and opposing arguments for issues regarding the Hg limit for lignite-fired EGUs. Comments received on the proposed repeal of the Hg limit for lignite-fired EGUs did not persuade the Agency to change its position from that set out in the proposed rule.

While the EPA found that all 22 existing lignite-fired EGUs at 12 facilities would need to control their Hg emissions to 95 percent or less to meet an emission standard of 1.2 lb/TBtu in the 2024 Final Rule,[120] the Agency did not demonstrate that this high level of Hg removal is generally achievable for all lignite-fired units in the source category while taking into account the wide-ranging and highly variable Hg content of the various lignite fuels. In fact, Hg emission rates reported in the 2024 Final Rule from units at 11 of the 12 lignite facilities were well above the final 1.2 lb/TBtu emission standard.[121] The EPA instead primarily relied on the emission reduction performance of only two units (at the Twin Oaks facility in Texas) that achieved the revised emission standard.[122] Between August 1 and September 19, 2023, a series of Hg emissions performance tests were conducted on Twin Oaks units 1 and 2. The average Hg emissions rates for the 30-boiler operating day performance tests were 1.1 lb/TBtu for unit 1 and 0.9 lb/TBtu for unit 2.[123] Further, in performance testing for the previous year (2022), the average Hg emissions rates for the 30-boiler operating day performance test were 0.9 lb/TBtu for unit 1 and 0.6 lb/TBtu for unit 2. However, these tests were conducted over a limited operating period

[120] Since the 2024 Final Rule, the Martin Lake and Limestone facilities have undergone permit changes that no longer allow the burning of lignite coal.
[121] 89 FR 38546 (May 7, 2024).
[122] *Id.* at 38539.
[123] *Id.* at 38540.

and are not sufficient to establish that meeting a 1.2 lb/TBtu standard continuously is possible for all lignite-fired EGUs.

Furthermore, the Twin Oaks facility, constructed in the early 1990s, is one of the newest lignite units and uses a circulating fluidized bed (CFB) combustor, which affects Hg emissions. Conventional boilers use coal that is pulverized to a very fine particle size (*i.e.*, powdered) to maximize combustion efficiency and to minimize unburned carbon. In contrast, the design of CFB combustors permits the burning of larger-sized coal particles. Fluidized bed units typically operate at lower temperatures compared to conventional boilers and have longer fuel residence times. As a result, CFB combustors typically have higher levels of unburned carbon present in the fly ash. The unburned carbon particles can behave much like injected activated carbon sorbent and, coupled with the lower operating temperature and longer residence time, can promote more efficient Hg removal as compared to that observed from units using non-CFB boilers with conventional pulverized coal combustors.

Other lignite-fired EGUs that utilize a CFB combustor also had generally lower Hg emission rates. For instance, the 2022 measured Hg rates reported in the 2024 Final Rule for the Red Hills facility in Mississippi, which also employs CFB combustors, was 1.7 lb/TBtu, compared to a range of 2.5 to 3.0 lb/TBtu for other lignite-fired EGUs in the southern U.S.[124] Additionally, the lowest 2022 Hg emissions from lignite-fired facilities in North Dakota were found at Spiritwood Station, which also utilizes a CFB combustor. In revising the Hg emission standard for lignite-fired EGUs in the 2024 Final Rule, the

[124] *Id.* at 38548.

EPA failed to evaluate the achievability of the revised Hg emission standard by affected sources that are not using the better performing CFB combustor technology.

In addition, the EPA assumed in the 2024 Final Rule that the revised Hg standard of 1.2 lb/TBtu could be met by injecting better performing powdered sorbents using existing sorbent injection systems without the need for equipment modifications or additions. However, industry commenters noted that existing equipment at lignite-fired power plants may not be able to achieve the 1.2 lb/TBtu Hg limit and that demonstration testing would be required to determine a sorbent dosage rate, guaranteed injection rate, and the emissions rate that can be achieved when considering the Hg content variability of the lignite. Commenters stated that modifications to Hg control systems may be required to meet the 1.2 lb/TBtu emission limit. The EPA did not consider such cost in the final analysis for the 2024 Final Rule.

In addition, the Agency did not sufficiently investigate the complex composition of lignite coals in the 2024 Final Rule, including the variability of the Hg content in the inlet fuel source and the corresponding reductions needed to comply with the 1.2 lb/TBtu Hg emission standard. In the 2023 proposed rule, the EPA explained how the halogen content of coal influences the oxidation state of Hg in the flue gas stream, and thus the partitioning of Hg into elemental Hg vapor, oxidized Hg vapor, or particle-bound Hg, which impacts the Hg control approaches.[125] Lignite and subbituminous coals both have a lower halogen content compared to bituminous coals, and the Hg in the flue gas from boilers firing those fuels tends to stay in the elemental vapor state, which is more challenging to control. The EPA noted that pre-halogenated (typically brominated)

[125] 88 FR 24875 (April 24, 2023).

sorbents have been effectively utilized to control Hg emissions at power plants firing low-halogen content subbituminous coals. However, the EPA also noted that lignite coals tend to contain higher amounts of sulfur (more similar to some bituminous coals), which, under certain circumstances, can result in the production of sulfur trioxide (SO_3) in the flue gas stream. SO_3, in turn, is known to inhibit the effectiveness of some sorbents that are used for Hg control. The EPA acknowledged the challenges with higher sulfur content coals but noted that bituminous coal-fired power plants found ways to overcome those challenges—sometimes by utilizing newly developed sulfur-tolerant sorbents. However, while the EPA acknowledged the respective challenges that the halogen and sulfur contents of coal can have on Hg control in the 2024 Final Rule, the EPA failed to address the impact of lower halogen content coupled with higher sulfur content on Hg control for lignite-fired power plants. Subbituminous coals tend to have low contents of both halogen and sulfur, while bituminous coals tend to contain higher levels of both halogen and sulfur. In comparison, lignites tend to have low halogen content (similar to subbituminous coals) and higher sulfur content (similar to bituminous coals).

Commenters also provided data challenging the assumed inlet value of 25.0 lb/TBtu used in modeling in the 2024 Final Rule. For example, historical data indicate that lignite seams near the San Miguel plant in Texas result in coal feeds that have an average Hg inlet content of 34.0 lb/TBtu.[126] As a result, San Miguel would need to achieve an average control rate of 96.3 percent to meet the standard in the 2024 Final Rule, compared to an 87.8 capture percentage for the 4.0 lb/TBtu emission limit .[127]

[126] Document ID No. EPA-HQ-OAR-2018-0794-5965.
[127] Document ID No. EPA-HQ-OAR-2018-0794-5965.

Additionally, monthly fluctuations in Hg content could require even higher control levels at least half the time. Ignoring monthly variability not only leads to an underestimation of costs associated with Hg removal but also overlooks control device modifications and enhancements required to achieve pollution control levels exceeding 90 percent.

It was not necessary to revise the Hg limit for lignite-fired EGUs in the 2024 Final Rule. This revised emission standard was based on insufficient data, and furthermore, the EPA did not demonstrate that the high level of Hg removal it required was generally achievable for all lignite-fired units in the source category while taking into account the wide-ranging and highly variable Hg content of the various lignite fuels. In addition, the Agency failed to evaluate its achievability by affected sources that are not using CFB combustor technology and assumed the revised standard could be met by injecting better performing sorbents without equipment modifications. The EPA also did not sufficiently investigate the complex composition of lignite coals, including the variability of the Hg content in the inlet fuel source, and ignored monthly variability, leading to an underestimation of costs. For these reasons, the EPA is finalizing the repeal of the Hg emission limit for lignite-fired EGUs that was promulgated in the 2024 Final Rule—1.2 lb/TBtu—and reverting to the Hg emission limit—4.0 lb/TBtu—that was promulgated in the 2012 MATS Rule.

3. What key comments did we receive on the Hg emission standard for lignite-fired EGUs and what are our responses?

Comment: Some commenters agreed with the EPA's proposed reconsideration of the Twin Oaks Hg data that the EPA relied upon in the 2024 Final Rule. First, commenters agreed the performance tests were conducted over a limited operating period and not sufficient to establish a more stringent Hg emission standard continuously for all units. Commenters argued that this facility was not representative of the national fleet because lignite seams burned at Twin Oaks differ from lignite at North Dakota lignite facilities and at other Texas lignite facilities. Second, commenters agreed that the CFB boiler design at the Twin Oaks and Red Hills facilities promote more efficient Hg removal compared to units using other types of boilers.

Other commenters disagreed with the EPA's proposed reconsideration of the Twin Oaks and Red Hills Hg data, arguing that the facilities' use of baghouses is an additional reason for highly effective Hg capture. These commenters asserted that while both facilities are equipped with ACI and would have very low SO_3 present in the flue gas due to high free lime content, the presence of a baghouse makes the ACI, as well as any intrinsic capture of fly ash, much more effective. These commenters stated that if an ESP was installed instead of a baghouse, Hg capture would be more difficult. However, commenters asserted that every lignite unit is already configured in a manner for potentially higher Hg capture. These commenters stated that lignite facilities equipped with baghouses include Antelope Valley, Coyote, Spiritwood, Twin Oaks, Oak Grove, and Red Hills, and that some of those facilities also have an upstream dry scrubber (Antelope Valley, Coyote, Spiritwood) that helps make Hg capture with ACI more effective. The remainder of the lignite facilities (Coal Creek, Leland Olds, Milton R Young, Limestone, Martin Lake, and San Miguel) installed ESPs followed by a wet FGD, which enable additional Hg capture beyond what is achieved with ACI because wet FGD removes oxidized Hg very efficiently.

These commenters further asserted that higher Hg capture is possible for lignite plants with pulverized coal boilers (*i.e.*, non-CFB units) and pointed to the Conemaugh power plant in Pennsylvania as an example. The Conemaugh facility is equipped with an ESP and wet FGD and burns bituminous coal. These commenters attempted to calculate the Hg content of coals burned at Conemaugh using EIA-923 data from 2016 to 2022, finding an average Hg content ranging from approximately 10 lb/TBtu to over 50 lb/TBtu with a standard deviation ranging from near zero to almost 40 lb/TBtu.[128] These commenters also asserted that most bituminous and subbituminous units receive coal from multiple mines and therefore face much greater variability in Hg content than lignite units, which are mine-mouth and only receive coal from one mine. Using the inferred Hg content information, commenters estimated that the Hg capture rate at the Conemaugh facility exceeded 95 percent every year, demonstrating that higher Hg capture at lignite units with lower Hg variability is possible using this configuration.

Response: The EPA agrees that baghouses are another technology for efficient Hg capture. However, the Agency did not demonstrate that higher Hg removal is achievable for all lignite-fired units once the wide-ranging and highly variable Hg content of the various lignite fuels is taken into account. As noted in the 2024 Final Rule, bituminous coals from Pennsylvania exhibit large Hg content variability similar to that of lignite, but bituminous coals also have higher natural chlorine content than lignite coal, which aids in the Hg removal efficiency.[129] Therefore, the Agency does not agree with the

[128] The survey Form EIA-923 collects detailed electric power data - monthly and annually - on electricity generation, fuel consumption, fossil fuel stocks, and receipts at the power plant and prime mover level. https://www.eia.gov/electricity/data/eia923/.
[129] 89 FR 38543 (May 7, 2024).

commenters' example that a facility burning bituminous coal using a pulverized coal boiler demonstrates that a similar lignite-fired unit can achieve a similar level of Hg control.

Comment: Commenters argued that the EPA failed to adequately justify returning to the 2012 MATS Rule Hg emission standard for lignite-fired EGUs in the proposed rule, as power plants that burn lignite coal represent a disproportionally large share of Hg emissions across all coal-fired EGUs. Specifically, commenters cited the 2023 proposal, in which the EPA provided that 16 of the top 20 Hg-emitting EGUs were lignite-fired and that lignite EGUs were responsible for about 30 percent of all Hg emitted from all coal-fired EGUs in 2021, while generating about 7 percent of total 2021 MW-hours.[130] Commenters noted that the 2012 MATS Rule resulted in a 90 percent reduction of Hg from power plants, but few reductions came from plants that burn lignite coal. The commenters explained that lignite-fired EGUs are concentrated geographically in North Dakota and Texas, which increases the cumulative burden of such pollutants on surrounding and downwind vulnerable communities.

Response: The EPA took all relevant comments and information, including information referenced above, into consideration when deciding whether to finalize the proposed repeal. Since the 2024 Final Rule, the Agency obtained updated information on the fleet of power plants burning lignite coal, finding that the Martin Lake and Limestone facilities (both in Texas) are no longer permitted to burn lignite and are now subject to a 1.2 lb/TBtu Hg emission standard. As mentioned earlier in this preamble, the 2020 Residual Risk Review found the residual risks due to emissions of air toxics to be

[130] 88 FR 24876 (April 24, 2023).

acceptable from the coal- and oil-fired EGU source category and determined that the current NESHAP (as promulgated in the 2012 MATS Rule) provided an ample margin of safety to protect human health and prevent an adverse environmental effect. Risk from near-field deposition of Hg to subsistence fishers was evaluated, using a site-specific assessment of a lake near three lignite-fired facilities.[131] The results suggest that methylmercury (MeHg) exposure to subsistence fishers from lignite-fired units alone is below the RfD for MeHg neurodevelopmental toxicity or IQ loss, with an estimated hazard quotient (HQ) of 0.06. In general, the EPA believes that exposures at or below the RfD are unlikely to be associated with appreciable risk of deleterious effects._The EPA reaffirmed its 2020 Residual Risk Review, which showed that emissions of HAP from coal- and oil-fired power plants have been reduced such that residual risk is at an acceptable level and provides an ample margin of safety, in the 2024 Final Rule.[132]

Comment: Many commenters agreed that the EPA did not appropriately consider costs for lignite EGUs to meet a revised Hg emission standard in the 2024 Final Rule. Commenters stated the cost to comply with the revised Hg emission standard depends on the amount and type of sorbent required and ACI equipment additions or modifications, and since the amount of sorbent needed to achieve a more stringent standard is unclear and unit-specific, the sorbent cost cannot be reliably calculated. Commenters also disagreed with the EPA's claim in the 2024 Final Rule that SO_3-tolerant sorbents could

[131] . Document ID No. EPA-HQ-OAR-2018-0794-0070
[132] In the 2024 Final Rule, the EPA stated: "In the 2023 Proposal, the EPA determined not to reopen the 2020 Residual Risk Review, and accordingly did not propose any revisions to that review. As the EPA explained in the proposal, the EPA found in the 2020 RTR that risks from the Coal- and Oil-Fired EGU source category due to emissions of air toxics are acceptable and that the existing NESHAP provides an ample margin of safety to protect public health." 89 FR 38518 (May 7, 2024).

be used at lower feed rates to achieve greater Hg capture. Commenters stated that the EPA underestimated costs in the 2024 Final Rule by not considering the costs of modifications to the Hg control systems to meet a more stringent Hg emission standard, especially for units equipped with an ESP instead of a FF. Commenters stated that compliance costs cannot be accurately estimated because no lignite EGU has demonstrated that the revised Hg emission standard can be met on a continuous basis. Commenters stated that these deficiencies in the Agency's cost analysis (*e.g.,* failure to include annual capitalized costs for the Hg control system, updated sorbent costs, and costs based on theoretical sorbent usage) resulted, for example, in at least a $2.6 million underestimate for Milton R Young Station's Unit 2.

Other commenters claimed that the EPA provided no evidence in the proposed rule, and did not appear to conclude, that costs of possible modifications to Hg control systems render the Hg standard either not "achievable" or not cost-effective. These commenters stated that although the EPA asserted in the proposed rule that it did not previously consider the cost of possible modifications to control systems to meet the revised Hg standard, the Agency had in fact considered these costs in the 2024 Final Rule and found them to be reasonable.[133] One of these commenters quoted a portion of the 2024 Final Rule in which the commenter believed that the EPA considered the costs of potential control system modifications and found that the need for "significant additional capital investment is unlikely."[134] Commenters asserted that the EPA stated in the 2024 Final Rule that the Agency expected sources to "be able to meet the revised emission

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[133] Document ID No. EPA-HQ-OAR-2018-0794-7609 (citing 89 FR 38508 (May 7, 2024).

[134] *Id.* (citing 89 FR 38549 (May 7, 2024)).

standard using existing controls (*e.g.*, using existing sorbent injection equipment)" and that "if site-specific conditions necessitate minor capital improvements to the ACI control technology, … any incremental capital cost would be small relative to ongoing sorbent costs accounted for in this analysis."[135]

Response: The EPA agrees with the commenters asserting that the Agency did not appropriately consider costs associated with Hg removal and overlooked costs for control device modification and enhancement required to achieve pollution control levels exceeding 90 percent within the 2024 Final Rule. In the 2024 Final Rule, the EPA noted that pre-halogenated (typically brominated) and sulfur-tolerant sorbents have effectively utilized to control Hg emissions at power plants firing low-halogen subbituminous coals. However, in the 2024 Final Rule, the EPA did not consider that the SO_3-tolerant sorbents had not been extensively tested on lignite-fired EGUs and thus the feed rates and associated costs are uncertain and therefore disagrees with those commenters that asserted costs for these sorbents are reasonable. Since subbituminous coals tend to have low content of both halogen and sulfur and bituminous coals tend to contain higher levels of both halogen and sulfur, whereas lignites generally have the combined characteristics of low halogen content and higher sulfur content, the EPA disagrees with those commenters that asserted associated costs to achieve greater Hg capture in lignite-fired EGUs were properly considered in the 2024 Final Rule.

[135] *Id.*

IV. Comments and Responses on the Relevance of Residual Risk to Technology Reviews under CAA Section 112(d)(6)

A. What did the EPA propose and solicit comment on regarding the relevance of residual risk to technology reviews under CAA section 112(d)(6)?

The EPA is finalizing the position that the Agency may consider the results of the one-time residual risk review requirement under CAA section 112(f)(2) in determining whether it is "necessary" to revise standards at the conclusion of subsequent CAA section 112(d)(6) technology reviews. Under CAA section 112(d)(6), the EPA is required "to review, and revise *as necessary* (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section no less often than every 8 years" (emphasis added). As noted in section II.A.1 of this preamble, the breadth of the term "necessary" in CAA section 112(d)(6) authorizes the EPA to consider the costs of revising standards in addition to the emissions-reduction potential of developments in practices, processes, and control technologies. Given the high costs and potential technical feasibility concerns with implementing the revised standards promulgated in the 2024 Final Rule, the EPA proposed to find that the 2024 revisions were not "necessary" under CAA section 112(d)(6) and solicited comment on whether and how the extent of further meaningful risk reduction opportunities should be considered in making that CAA section 112(d)(6) determination (Question #8). As explained in section II of this preamble, the EPA found in its 2020 Residual Risk Review that the residual risks due to HAP emissions from this source category are acceptable and determined that the current NESHAP (as promulgated in the 2012 MATS Rule) provided an ample margin of safety to protect public health and prevent an adverse environmental effect. The EPA reaffirmed the 2020 Final Rule, and did not reopen any of the underlying findings or conclusions of the one-time residual risk review requirement for MATS, in the 2024 Final Rule.[136]

B. What is the EPA finalizing regarding the relevance of residual risk to technology reviews under CAA section 112(d)(6)?

As previewed in section III.A of this preamble, the EPA concludes that subsequent technology reviews under CAA section 112(d)(6) may consider the results of the one-time residual risk review requirement under CAA section 112(f)(2) in determining whether revisions are "necessary." Specifically, the EPA will generally place greater weight on the cost of revising standards when the results of the one-time residual risk review requirement indicate that cancer risk from HAP emissions are less than the statute's aspirational goal of one in one million. Under those circumstances, revisions will generally be "necessary" only when costs are at the low end of the range of acceptability. This interpretation follows from the term "necessary" in CAA section 112(d)(6), which gives the Agency discretion to consider relevant factors and

[136] *See* 89 FR 38518 (May 7, 2024). The results of the risk analysis indicated that both the actual and allowable inhalation cancer risk to the individual most exposed was well below 100-in-1 million, which is the EPA's presumptive limit of acceptability under the Benzene NESHAP. The results of the chronic inhalation cancer risk assessment based on actual emissions, as shown in Table 2 of this preamble, indicated that the estimated maximum individual lifetime cancer risk (cancer MIR) was 9-in-1 million, with nickel emissions from certain oil-fired EGUs as the major contributor to the risk. Approximately 193,000 people were estimated to have cancer risks at or above 1-in-1 million from HAP emitted from four facilities in this source category—all from oil-fired sources in Puerto Rico. However, the 2024 Final Rule only required controls for certain types of coal-fired EGUs and would not impact emissions from these oil-fired facilities.

information, including information in the record for the NESHAP under review.[137] It is also consistent with the risk thresholds that Congress wrote into the statute, including the requirement to promulgate additional standards when cancer risk exceeds the aspirational goal of one in one million and the presumptive unacceptability threshold of 100 in one million expressly incorporated as part of the Benzene NESHAP approach.[138]

Commenters provided supportive and opposing arguments as to whether a technology review conducted under CAA section 112(d)(6) should take into consideration whether any meaningful risk reduction would be obtained from further reducing HAP emissions under the technology review given the results of the residual risk review. The EPA has taken these comments into account in finalizing its position on the question and summarizes and responds to many of the most significant comments in the following section. Additional discussion, including further comment summaries and responses, are available in the Response to Comment document available in the docket for this rule.

C. What key comments did the EPA receive regarding the relevance of residual risk to technology reviews under CAA section 112(d)(6), and what are our responses?

Comment: Commenters agreed that the EPA should consider the potential for and materiality of risk reductions when conducting a CAA section 112(d)(6) technology

[137] *LEAN*, 955 F.3d at 1097 (parenthetical in CAA section 112(d)(6) points to non-exhaustive list of considerations); *see also Michigan*, 576 U.S. at 752-53 (the term "appropriate and necessary" in CAA section 112(n)(1) directs agency to consider all relevant factors in exercising discretion); *Nat'l Ass'n for Surface Finishing*, 795 F.3d at 9-11 (discussing the EPA's discretion to consider relevant information when determining relevant information is "necessary"); *Ass'n of Battery Recyclers*, 716 F.3d at 673-74 (similar).
[138] CAA section 112(f)(2)(B), 42 U.S.C. 7412(f)(2)(B).

review, citing multiple reasons. First, commenters argued that CAA section 112(d)(6) allows the EPA to revise standards only when "necessary," which should be determined by assessing whether new regulations protect human health and the environment. Commenters stated that in *Michigan*, the Supreme Court explained that the EPA must consider costs when it evaluates benefits in deciding whether the 2012 MATS Rule was "appropriate and necessary," and that case should similarly require the Agency to conduct a cost-benefit analysis to any new revisions under CAA section 112(d)(6). Commenters listed previous rules where the Agency used the lack of meaningful risk reduction as a factor in its cost analysis, such as the Industrial Process Cooling Towers NESHAP RTR,[139] Petroleum Refineries NESHAP RTR,[140] Halogenated Solvent Cleaning NESHAP reconsideration proposal,[141] and Organic Hazards Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry NESHAP RTR.[142] Commenters also noted that in the RTR for the Coke Oven Batteries NESHAP, the EPA stated generally that findings concerning risk that the EPA makes in a section 112(f)(2) determination may be relevant in making any subsequent 112(d)(6) determinations for the related 112(d) standard.[143]

[139] *National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers*, 71 FR 17729, 17731-32 (April 7, 2006).
[140] *National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*, 72 FR 50716, 50730 (September 4, 2007).
[141] *National Emission Standards for Hazardous Air Pollutants for Halogenated Solvent Cleaning*, 73 FR 62384, 62404 (October 20, 2008).
[142] *National Emission Standards for Hazardous Air Pollutants for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry*, 71 FR 76603, 76606 (December 21, 2006).
[143] *National Emission Standards for Coke Oven Batteries*, 70 FR 19992, 20009 (April 15, 2005).

Second, commenters noted that the residual risk of HAP emissions from coal-fired EGUs are minimal under the MACT standards from the 2012 MATS Rule. Specifically, commenters noted that the EPA's 2020 Residual Risk Review found that the maximum lifetime cancer risk from coal-fired EGUs ranged from 0.002 to 0.344 in 1 million, which, commenters asserted, are orders of magnitude below what commenters further asserted is Congress's threshold for deregulating the source category. Commenters argued that further reducing cancer risks that are already less than one in one million yields negligible benefits, if any.

Other commenters disagreed that the EPA should consider residual risk during a CAA section 112(d)(6) technology review, arguing that the proposed rule misconstrues the technology review process under CAA section 112(d)(6) and fails to apply the best reading of the statute. These commenters stated that the EPA must review any new developments in control technologies and explain why those new developments make it necessary to adopt new standards. These commenters stated that the proposed rule is arbitrary and capricious because the EPA failed to consider any developments in practices, processes, and control technologies in finding that rescission is necessary. In the proposed rule, the Agency stated that "[g]iven the high costs and potential feasibility concerns with implementing the revised standards . . . the 2024 changes were not necessary under CAA section 112(d)(6)."[144] However, these commenters argued that the EPA added no new information or analysis concerning developments in practices, processes, and control technologies—the rulemaking record is essentially identical to that underlying the 2024 Final Rule, as the EPA recognized in its 2025 RIA. Instead, these

[144] 90 FR 25544 (June 17, 2025).

commenters argued, the EPA now determines that the 2024 changes were not necessary in a conclusory manner, only citing changes in the Administrator's policy preferences at the EPA as "developments" rather than citing any factual developments in practices, processes, or control technologies at emissions sources.

Lastly, these commenters claimed that CAA section 112(d)(6) does not allow the EPA to withdraw revised standards based on its claim that otherwise achievable controls produce no "meaningful risk reduction." These commenters also argued that the EPA provided no reasonable basis to conclude that the 2012 MATS Rule still provides the maximum degree of emission reduction achievable under CAA section 112(d)(2), instructing the EPA to "tak[e] into account developments in practices, processes, and control technologies." These commenters asserted that the EPA may not decline to make otherwise "necessary" revisions based on its appraisal of risk reduction.

Response: The EPA agrees that the Agency has an independent statutory authority and obligation to conduct technology reviews every 8 years separate from the EPA's obligation to conduct a one-time residual risk review within 8 years of setting the MACT. The D.C. Circuit has recognized the CAA section 112(d)(6) technology review and CAA section 112(f)(2) residual risk review are "distinct, parallel analyses" that the EPA undertakes "[s]eparately."[145] It would be inconsistent with the text, structure, and legislative history of the CAA for the EPA to conclude that Congress intended the statute's technology-based approach to be sidelined after the Agency concludes the risk review, particularly because technology reviews, unlike the residual risk review, must be completed every 8 years on an ongoing basis. In the past, the EPA has occasionally

[145] *Nat'l Ass'n for Surface Finishing*, 795 F.3d at 5.

determined that additional controls were warranted under technology reviews pursuant to CAA section 112(d)(6) although additional standards were not necessary to maintain an ample margin of safety under CAA section 112(f)(2).[146] The EPA has also previously stated that it "disagree[s] with the view that a determination under CAA section 112(f) of an [ample margin of safety] and no adverse environmental effects alone will, in all cases, cause us to determine that a revision is not necessary under CAA section 112(d)(6)."[147]

However, the EPA also agrees with commenters' assertions that costs should be considered in relation to potential benefits when evaluating whether revisions are "necessary" under CAA section 112(d)(6). That concept is inherent in the EPA's consideration of standard cost metrics, including cost effectiveness expressed as cost per ton of HAP emissions abated. HAP emissions figures are important because of the health and environmental impacts they represent, and it is reasonable to consider such impacts when determining whether to regulate. As noted earlier in this preamble, the EPA has

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[146] *See*, *e.g.*, *National Emission Standards for Hazardous Air Pollutants: Refractory Products Manufacturing Residual Risk and Technology Review*, 86 FR 66045 (November 19, 2021); *National Emission Standards for Hazardous Air Pollutants: Site Remediation Residual Risk and Technology Review*, 85 FR 41680 (July 10, 2020); *National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) Residual Risk and Technology Review*, 85 FR 40740, 40745 (July 7, 2020); *National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology Standards Residual Risk and Technology Review for Ethylene Production*, 85 FR 40386, 40389 (July 6, 2020); *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills*, 82 FR 47328 (October 11, 2017); *National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology Standards; and Manufacture of Amino/Phenolic Resins*, 79 FR 60898, 60901 (October 8, 2014).
[147] *National Emission Standards for Hazardous Air Pollutant Emissions: Group I Polymers and Resins; Marine Tank Vessel Loading Operations; Pharmaceuticals Production; and the Printing and Publishing Industry*, 76 FR 22566, 22577 (April 21, 2011).

long evaluated cost effectiveness in the context of particular HAP because different HAPs present different physical and risk characteristics. That concept is also inherent in the nature of cost consideration. As the Supreme Court explained in *Michigan*, "[c]onsideration of cost reflects the understanding that reasonable regulation ordinarily requires paying attention to the advantages *and* the disadvantages of agency decisions," and it would be irrational "to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits."[148]

As explained in section III.A of this preamble, there are circumstances in which the EPA may consider risk in a CAA section 112(d)(6) rulemaking as part of its determination of whether revisions to emission standards are "necessary." The EPA concludes that in the present rulemaking, it may consider the small remaining risk from the non-HG HAP metals emitted from the source category – the cancer risks are less than one in one million for every coal-fired EGU in the source category – in assessing whether the costs of controls for those pollutants are too high, such that a revision to the standards based on those controls is not "necessary." This conclusion is consistent with previous rules under CAA section 112(d)(6) in which the EPA has considered risk.

V. What is the rationale for other final decisions and amendments from the reevaluation of the 2024 Final Rule?

In 2020, the EPA finalized electronic data reporting requirements of MATS, including requiring data availability in Extensible Markup Language (XML) format and amending the reporting and recordkeeping requirements associated with performance

[148] 576 U.S. at 752-53.

stack tests, PM and HCl CEMS, and PM CPMS.[149] As a result, sources are required to use the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool to submit all required reports. The deadline to meet changes in electronic reporting was December 31, 2023, which has since been tentatively extended to the 1st quarter of 2026.

As part of this rulemaking, the EPA is finalizing two minor technical, non-substantive clarifications to the relevant electronic data reporting requirements, such as (i) removing references to “ECMPS” and replacing with “ECMPS Reporting Tool” and (ii) revising the XML file format requirement to any file format specified by the Administrator. The main effect of these minor technical clarifications is that they make clear that the EPA will accept MATS reports in both XML and PDF (or other) formats, as opposed to only XML. These minor technical clarifications will better clarify and enable the reporting of electronic compliance data, in light of the fact that some reporting aspects are not supported by XML.

The EPA is making these non-substantive clarifications including under the “good cause” exception to notice-and-comment rulemaking incorporated by reference into the statute in CAA section 307. Under section 553(b)(B) of the Administrative Procedure Act, an agency may forego notice-and-comment rulemaking when it “for good cause find[s]” that providing notice and an opportunity for comment would be “impracticable, unnecessary, or contrary to the public interest.” Here, providing notice is “unnecessary”

[149] 85 FR 55744 (September 9, 2020).

because of the minor, non-substantive nature of the technical clarifications.[150] As these changes do not alter the substantive reporting requirements, there is good cause to make them without prior notice and comment. The Agency emphasizes that these non-substantive clarifications are separate and independent from any other change made in this final rule.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders is available 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 a significant action under E.O. 12866 section 3(f)(1) that was submitted to the OMB for review. Any changes made in response to E.O. 12866 review have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final Repeal of Amendments to National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*, is available in the docket.[151]

We present the estimated present values (PV) and equivalent annualized values (EAV) of the estimated cost savings of repealing the 2024 Final Rule in 2024 dollars over

[150] *See Mack Trucks, Inc. v. EPA*, 682 F.3d 87, 94 (D.C. Cir. 2012) ("This prong of the good cause inquiry is 'confined to those situations in which the administrative rule is a routine determination, insignificant in nature and impact, and inconsequential to the industry and to the public.'") (quoting *Util. Solid Waste Activities Grp. v. EPA*, 236 F.3d 749, 755 (D.C. Cir. 2001)).
[151] Docket ID No. EPA-HQ-OAR-2018-0794.

the 2028 to 2037 period, discounted to 2025. In addition, the Agency presents the assessment for specific snapshot years, consistent with historic practice. These snapshot years are 2028, 2030, and 2035. The power industry's cost savings are represented in this analysis as the change in electric power generation costs due to the repeal of the 2024 Final Rule requirements. In simple terms, these cost savings are an estimate of the decreased power industry expenditures resulting from the repeal of the 2024 Final Rule requirements.

Under this final repeal, the 2024 Final Rule would no longer reduce emissions of Hg and non-Hg HAP metals as projected in the 2024 MATS RTR RIA.[152] The potential benefits from reductions of HAP were not able to be monetized in the 2024 MATS RTR RIA, nor were potential impacts from the 2024 Final Rule requirement to use PM CEMS for compliance demonstration. See section I.A for more details of the final repeal of requirements.

Table 4 presents the estimated cost savings of this final action in 2024 dollars discounted to 2025. This table presents the PV and EAV of these estimates discounted at 3 percent and 7 percent.

Table 4—Present Value and Equivalent Annualized Value of Compliance Cost Savings Estimates of the Final Repeal from 2028-2037 (Millions of 2024$, Discounted to 2025)

	3 Percent Discount Rate	**7 Percent Discount Rate**
Present Value	670	490
Equivalent Annualized Value	78	69

Note that, unlike the proposal, the compliance cost analysis for the final rule

[152] "Regulatory Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review" (Ref. EPA-452/R-24-005). Document ID No. EPA-HQ-OAR-2018-0794-6966.

reflects the recent Presidential Proclamations that temporarily exempt certain stationary sources from compliance with the 2024 MATS RTR requirements. Additionally, this updated analysis incorporates recent updates to state and federal legislation affecting the power sector, including the One Big Beautiful Bill Act (OBBBA) of 2025, and also accounts for large projected increases in electricity demand stemming from data centers and Artificial Intelligence applications.

The EPA is obligated to present the agency's best scientific understanding and the implications of that science when developing policies and regulations. However, the EPA's analytical practices may not have presented the full range of uncertainties and associated confidence level regarding the potential benefit estimates from reduction in exposure from fine particulate matter ($PM_{2.5}$) and ozone. In addition, the science regarding the exposure, health effects from exposure and valuation of reduction in health effect are evolving with better data and methods, especially at low concentrations of PM and ozone. The EPA's use of benefit per ton (BPT) monetized values introduces additional uncertainty. Although developed as a screening tool when full-form photochemical modeling was not feasible, the BPT approach reduces complex spatial and atmospheric relationships and may be more suited to model emissions that are geographically more uniform and species better mixing, thereby adding uncertainty associated with those estimates. Some of the sources of uncertainties include the set of assumptions used in projecting the health impact of reducing particulate matter. These projections are based on a series of models that take into account emissions changes, resulting distributions of changes in ambient air quality, the estimated reductions in health effects from changes in exposure, and the composition of the population that will benefit from the reduced exposure. Each component includes assumptions, each with varying degrees of uncertainty.

In addition, the EPA historically provided point estimates rather than just ranges of emission-related effects or only quantifying emissions when monetizing proved to be too uncertain. Therefore, to address these concerns, the EPA is refraining in providing primary estimates resulting from changes in $PM_{2.5}$ and ozone exposure resulting from changes in NOx emissions but will continue to quantify the emissions until the Agency if confident enough in the modeling to robustly monetize those impacts.

A more robust description of the benefits and cost of this rulemaking is contained in the RIA, available in the docket, and is consistent with Executive Order 12866.

B. Executive Order 14192: Unleashing Prosperity Through Deregulation

This action is considered an Executive Order 14192 deregulatory action. Details on the estimated cost savings of this final rule is available in the EPA's analysis of the potential costs and benefits associated with this action.

C. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2137.13. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0567. The information collection activities in this rule include performance testing, continuous emission monitoring, notifications and periodic reports, recording information, monitoring and the maintenance of records. The information generated by these activities will be used by the EPA to ensure that affected facilities comply with the emission limits and other requirements. Records and reports are necessary to enable delegated authorities to identify affected facilities that may not be in compliance with the requirements. Based on reported information, delegated authorities will decide which units and what records or processes should be inspected. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). The burden and cost estimates below represent the total burden and cost for the information collection requirements of the NESHAP for coal- and oil-fired EGUs, not just the burden associated with the amendments in this final rule. The incremental ICR cost savings associated with the final repeal of these amendments is $29.8 million per year.

Respondents/affected entities: The respondents are owners or operators of coal- and oil-fired EGUs. The NAICS codes for the coal- and oil-fired EGU industry are 221112, 221122, and 921150.

Respondent's obligation to respond: Mandatory per 42 U.S.C. 7414 *et seq.*

Estimated number of respondents: 201 per year. Each facility is a respondent, and some facilities have multiple EGUs.

Frequency of response: The frequency of responses varies depending on the burden item. Responses include daily calibrations, monthly recordkeeping activities, semiannual compliance reports, and annual reports.

Total estimated burden: 191,000 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $76,800,000 (per year); includes $24,800,000 annualized labor costs, $4,500,000 annualized capital costs, and 47,500,000 annualized operation & 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. When OMB approves this ICR, the Agency will announce that approval in the *Federal Register* and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

D. Regulatory Flexibility Act (RFA)

The EPA certifies that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the EPA concludes that the impact of concern for this rule is any significant adverse economic impact on small entities, and the Agency is certifying that this rule will not have a significant economic impact on a substantial number of small entities because of the overall cost savings for and low impact on small entities. This final action will lead to reduction in EAV of costs over the 2028 to 2037 timeframe of about $78 and $69 million per year at discount rates of three percent and seven percent, respectively. A small entity analysis was conducted, reflecting updated modeling assumptions, and focusing on analysis year 2030, when the two-year exemptions will end for all affected units and full compliance of the 2024 MATS RTR requirements would be expected. This analysis identified one unit that is estimated to experience a fuel use and electricity generation change of at least one percent and is own by an entity that is considered small. This small entity is not estimated to have a significant change in cost relative to its revenue as a result of the final repeal. Consequently, the EPA expects that this deregulatory action will relieve overall regulatory burden for facilities that, absent this final action, would be affected by the provisions from the 2024 Final Rule.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more (adjusted for inflation) as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The costs involved in this action are estimated not to exceed $100 million or more (adjusted for inflation) in any one year.

F. 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.

G. 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 the action.

Consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA consulted with Tribal officials during the development of this action. A summary of the two consultations with the Lake Paiute Tribe and Summit Lake Tribe is provided in the docket.

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

Executive Order 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. 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. Emissions from this source category include HAP like Hg and lead, which are known developmental toxicants. However, the 2020 residual risk assessment showed all modeled exposures to HAP from these facilities to be below levels of public health concern (85 FR 31286). Therefore, this action does not present or address disproportionate risk to children.

I. 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 2024 MATS RTR RIA projected that the 2024 Final Rule would have minimal impacts on average retail electricity prices across the contiguous U.S., coal-fired electricity generation, natural gas-fired electricity generation, and utility power sector delivered natural gas prices. Details of the projected energy impacts are presented in section 2 of the RIA, which is in the rulemaking docket.

J. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

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 meets the criteria set forth in 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 63

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

Lee Zeldin,
Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency amends part 63 of title 40, chapter I, of the Code of Federal Regulations as follows:

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

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

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

Subpart A—General Provisions

2. Amend § 63.14 by revising paragraph (f)(1) to read as follows:

§ 63.14 Incorporation by reference.

* * * * *

(f) * * *

(1) ANSI/ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], issued August 31, 1981; §§ 63.116(c) and (h); 63.128(a); 63.145(i); 63.309(k); 63.365(b); 63.457(k); 63.490(g); 63.772(e) and (h); 63.865(b); 63.997(e); 63.1282(d) and (g); 63.1450(a), (b), (d), (e), (g); 63.1625(b); table 5 to subpart EEEE; §§ 63.3166(a); 63.3360(e); 63.3545(a); 63.3555(a); 63.4166(a); 63.4362(a); 63.4766(a); 63.4965(a); 63.5160(d); table 4 to subpart UUUU; tables 5, 16, and 17 to subpart XXXX; table 3 to subpart YYYY; table 4 to subpart AAAAA; § 63.7322(b); table 5 to subpart DDDDD; §§ 63.7822(b); 63.7824(e); 63.7825(b); 63.8000(d); table 4 to subpart JJJJJ; table 4 to subpart KKKKK; §§ 63.9307(c); 63.9323(a); 63.9621(b) and (c); table 4 to subpart SSSSS; table 5 of subpart UUUUU; table 1 to subpart ZZZZZ; §§ 63.11148(e); 63.11155(e); 63.11162(f); 63.11163(g); table 4 to subpart JJJJJJ; §§ 63.11410(j); 63.11551(a); 63.11646(a); 63.11945.

* * * * *

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

3. Amend § 63.9991 by revising paragraph (a)(2) to read as follows:

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) * * *

(2) You must meet each operating limit in table 4 to this subpart that applies to your EGU.

* * * * *

4. Amend § 63.10000 by revising paragraphs (c)(1)(i), (c)(1)(iv), (c)(2)(i) and (ii), and (d)(5)(i) to read as follows:

§ 63.10000 What are my general requirements for complying with this subpart?

* * * * *

(c) * * *

(1) * * *

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct initial performance testing in accordance with § 63.10005(h), to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs (c)(1)(i)(A) and (B) of this section:

(A) Except as provided in paragraph (c)(1)(i)(C) of this section, you may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device.

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-derived fuel-fired EGU or IGCC EGU is new.

(C) You may pursue the LEE option provided that:

(*1*) Your EGU's control device bypass emissions are measured in the bypass stack or duct or your control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event; or

(*2*) Except for hours during which only clean fuel is combusted, you bypass your EGU control device only during emergency periods for no more than a total of 2 percent of your EGU's annual operating hours; you use clean fuels to the maximum extent possible during an emergency period; and you prepare and submit a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. You must include these emergency emissions along with performance test results in assessing whether your EGU maintains LEE status.

*   *   *   *   *

(iv) If your coal-fired or solid oil derived fuel-fired or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

* * * * *

(2) * * *

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(ii) If your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly.

* * * * *

(d) * * *

(5) * * *

(i) Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See § 63.10010(a) for further details. For PM CPMS installations, follow the procedures in § 63.10010(h).

*   *   *   *   *

5. Amend § 63.10005 by revising paragraph (a)(1), introductory text of paragraph (b), paragraph (c), and introductory text of paragraphs (d)(2), (h), and (h)(1) to read as follows:

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) *   *   *

(1) To demonstrate initial compliance with an applicable emissions limit in table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If you are required to establish operating limits (see paragraph (d) of this section and table 4 to this subpart), you must collect all applicable parametric data during the performance test period. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

*   *   *   *   *

(b) *Performance testing requirements.* If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to § 63.10007 and table 5 to this subpart. Notwithstanding these requirements, when table 5 specifies the use of isokinetic EPA test Method 5, 5D, 5I, 26A, or 29 for a stack test, if concurrent measurement of the stack gas flow rate or moisture content is needed to convert the pollutant concentrations to units of the standard, separate determination of these parameters using EPA test Method 2 or EPA test Method 4 is not necessary. Instead, the stack gas flow rate and moisture content can be determined from data that are collected during the EPA test Method 5, 5D, 5I, 6, 26A, or 29 test (e.g., pitot tube (delta P) readings, moisture collected in the impingers). For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in § 63.9984, provided that the following conditions are fully met:

*   *   *   *   *

(c) *Operating limits.* In accordance with § 63.10010 and table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration.

(d) *   *   *

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS:

*   *   *   *   *

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may pursue this compliance option unless prohibited pursuant to § 63.10000(c)(1)(i).

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF,

filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h) and if those data demonstrate:

* * * * *

6. Amend § 63.10006 by revising paragraph (a) to read as follows:

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under § 63.10000(c), you must conduct all applicable performance tests according to table 5 to this subpart and § 63.10007 at least every year.

* * * * *

7. Amend § 63.1007 by revising paragraphs (a)(3) and (c) to read as follows:

§ 63.10007 What methods and other procedures must I use for the performance tests?

(a) * * *

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non-Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

* * * * *

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b), § 63.10023, and tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

* * * * *

8. Amend § 63.10010 by revising the introductory text of paragraphs (a), (h), and (i) to read as follows:

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

* * * * *

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

* * * * *

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal

HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record and report the output of the PM CEMS as specified in paragraphs (i)(1) through (8) of this section. Compliance with the applicable PM emissions limit in table 1 or 2 to this subpart is determined on a 30-boiler operating day rolling average basis.

* * * * *

9. Amend § 63.10011 by revising paragraph (b) to read as follows:

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

* * * * *

(b) If you are subject to an operating limit in table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil fired EGU, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with § 63.10007 and table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (i.e., tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

* * * * *

10. Amend § 63.10020 by revising paragraph (e)(3)(i) introductory text to read as follows:

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

* * * * *

(e) * * *

(3) * * *

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non- liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CMS, you must:

* * * * *

11. Amend § 63.10021 by revising paragraph (c) introductory text and paragraph (f) to read as follows:

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

* * * * *

(c) If you use PM CPMS data to measure compliance with an operating limit in table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30-boiler operating day average.

Equation 9 to paragraph (c)

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad (Eq.\ 9)$$

Where:
Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30-boiler operating days.

* * * * *

(f) You must submit the applicable reports and notifications required under § 63.10031(a) through (k) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) reporting tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS reporting tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS reporting tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved.

* * * * *

12. Amend § 63.10022 by revising paragraphs (a)(2) and (3) to read as follows:

§ 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) * * *

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test;

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

* * * * *

13. Amend § 63.10023 by removing the introductory text to the section.

14. Amend § 63.10030 by revising paragraph (e)(3) to read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(e) * * *

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (e.g., use of PM CPMS); CEMS; or a sorbent trap monitoring system.

* * * * *

15. Amend § 63.10031 by revising paragraph (a)(4), paragraph (a)(5) introductory text, paragraphs (f)(2) and (f)(4), paragraph (f)(6) introductory text, and paragraphs (g) through (k) to read as follows:

§ 63.10031 What reports must I submit and when?

(a) * * *

(4) If you elect to demonstrate continuous compliance using a PM CPMS, you must meet the electronic reporting requirements of appendix D to this subpart. Electronic reporting of the hourly PM CPMS output shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS.

(5) If you elect to monitor SO_2 emission rate continuously as a surrogate for HCl, you must use the ECMPS reporting tool to submit the following information to EPA (except where it is already required to be reported or has been previously provided under the Acid Rain Program or another emissions reduction program that requires the use of part 75 of this chapter):

* * * * *

(f) * * *

(2) If, for a particular EGU or a group of EGUs serving a common stack, you have elected to demonstrate compliance using a PM CEMS, an approved HAP metals CMS, or a PM CPMS, you must submit quarterly PDF reports in accordance with paragraph (f)(6) of this section, which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in

paragraph (g) of this section. In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CMS, the quarterly compliance reports described in paragraph (g) of this section must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO_2, if you have elected to (or are required to) continuously monitor these pollutants. Further, if your EGU or common stack is in an averaging plan, your quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group.

* * * * *

(4) You must submit semiannual compliance reports as required under paragraphs (b) through (d) of this section, ending with a report covering the semiannual period from July 1 through December 31, 2023, and Notifications of Compliance Status as required under § 63.10030(e), as PDF files. Quarterly compliance reports shall be submitted in a format specified by the Administrator, thereafter, in accordance with paragraph (g) of this section, starting with a report covering the first calendar quarter of 2024.

* * * * *

(6) All reports and notifications described in paragraphs (f) introductory text, (f)(1), (2), and (4) of this section shall be submitted to the EPA in the specified format and at the specified frequency, using the ECMPS reporting tool. Each PDF version of a stack test report, CEMS RATA report, PM CEMS correlation test report, RRA report, and RCA report must include sufficient information to assess compliance and to demonstrate that the reference method testing was done properly. Note that EPA will

continue to accept, as necessary, PDF reports that are being phased out at the end of 2023, if the submission deadlines for those reports extend beyond December 31, 2023. The following data elements must be entered into the ECMPS reporting tool at the time of submission of each PDF file:

*   *   *   *   *

(g) Starting with a report for the first calendar quarter of 2024, you must use the ECMPS reporting tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of appendix E to this subpart. For each stack test summarized in the compliance report, you must also submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter.

(h) On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR 63.9(h)(2)(ii), as PDF files, using the ECMPS reporting tool. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into the ECMPS reporting tool with each Notification.

(i) If you have elected to use paragraph (2) of the definition of “startup” in § 63.10042 (only allowed before January 2, 2025), then, for startup and shutdown incidents that occur on or prior to December 31, 2023, you must include the information in § 63.10031(c)(5) in the semiannual compliance report, in a PDF file. If you have elected to use paragraph (2) of the definition of “startup” in § 63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, you must use the ECMPS reporting tool to submit the information in § 63.10031(c)(5) and § 63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into the ECMPS reporting tool with each startup and shutdown report.

(j) If you elect to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with this subpart and have begun recording valid data from the PM CEMS prior to November 9, 2020, you must use the ECMPS reporting tool to submit a detailed report of your PS 11 correlation test (see appendix B to part 60 of this chapter) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, you must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, you must submit the PDF report according to section 7.2.4 of appendix C to this subpart. The applicable data elements in paragraph (f)(6)(i) through (xii) of this section must be entered into the ECMPS reporting tool with the PDF report.

(k) If you elect to demonstrate compliance using a PM CPMS or an approved HAP metals CMS, you must submit quarterly reports of your QA/QC activities (e.g., calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CMS is used for the compliance demonstration in that quarter. Otherwise, submit a report for the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in paragraph (f)(6)(i) through (xii) of this section must be entered into the ECMPS reporting tool with the PDF report.

16. Amend § 63.10032 by revising paragraph (a) introductory text to read as follows:

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if you elect to use a PM CPMS, you must keep the records required under appendix A and/or appendix B and/or appendix C and/or appendix D to this subpart. If you elect to conduct periodic (e.g., quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, you must keep records of the applicable data elements under 40 CFR 63.7(g). You must also keep records of all data elements and other information in appendix E to this subpart that apply to your compliance strategy.

*   *   *   *   *

17. Amend § 63.10042 by adding the definition "stationary combustion turbine" to read as follows:

§ 63.10042 What definitions apply to this subpart?

*   *   *   *   *

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

*   *   *   *   *

18. Revise tables 1, 2, 4, 5, 6, 7, and 8 to subpart UUUUU of part 63 to read as follows:

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

As stated in § 63.9991, you must comply with the following applicable emission limits:

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	9.0E-2 lb/MWh[1]	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	

	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 3 dscm per run. For ASTM D6348-03 (Reapproved 2010)[2] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal	a. Filterable particulate matter (PM)	9.0E-2 lb/MWh[1]	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	

	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run For ASTM D6348-03 (Reapproved 2010)[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E-2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	7.0E-2 lb/MWh[4] 9.0E-2 lb/MWh[5]	Collect a minimum catch of 3.0 milligrams or a minimum sample volume of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	

	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E-2 lb/GWh	
	Arsenic (As)	2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	4.0E-2 lb/GWh	
	Cobalt (Co)	4.0E-3 lb/GWh	
	Lead (Pb)	9.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	7.0E-2 lb/GWh	
	Selenium (Se)	3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A-8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010)[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	4.0E-1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit - continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E-4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.

	Antimony (Sb)	1.0E-2 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	5.0E-4 lb/GWh	
	Cadmium (Cd)	2.0E-4 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-2 lb/GWh	
	Lead (Pb)	8.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	9.0E-2 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	1.0E-4 lb/GWh	For Method 30B at appendix A-8 to part 60 of this chapter sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1⁄2 the standard.
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 (Reapproved 2010)[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 (Reapproved 2010)[2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit - non-continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	2.0E-1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.

	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	6.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-1 lb/GWh	
	Lead (Pb)	3.0E-2 lb/GWh	
	Manganese (Mn)	1.0E-1 lb/GWh	
	Nickel (Ni)	4.1E0 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010)[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 (Reapproved 2010)[2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	3.0E-2 lb/MWh[1]	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	

	Total non-Hg HAP metals	6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	7.0E-4 lb/GWh	
	Chromium (Cr)	6.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	7.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	6.0E-3 lb/GWh	
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 (Reapproved 2010)[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E-3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross output.
[2] Incorporated by reference, see § 63.14.
[3] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2 CEMS installed.
[4] Duct burners on syngas; gross output.
[5] Duct burners on natural gas; gross output.

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

As stated in § 63.9991, you must comply with the following applicable emission limits:[1]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh[2]	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	

	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh	For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010)[3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A-8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
		OR	
		1.0E0 lb/TBtu or 1.1E-2 lb/GWh	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

2. Coal-fired unit low rank virgin coal	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh[2]	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance demonstration. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	

	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26 at appendix A-8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh[2]	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 3.0 milligrams or a minimum sample volume of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E-2 lb/GWh	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E-2 lb/GWh	

	Beryllium (Be)	1.0E-1 lb/TBtu or 1.0E-3 lb/GWh	
	Cadmium (Cd)	1.5E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E-2 lb/GWh	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	5.0E-4 lb/MMBtu or 5.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit - continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh[2]	Collect a minimum of 1 dscm per run.
	OR	OR	

	Total HAP metals	8.0E-4 lb/MMBtu or 8.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E-1 lb/GWh	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E-2 lb/GWh	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E-2 lb/GWh	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E-2 lb/GWh	
	Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 1.0E-2 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.

	c. Hydrogen fluoride (HF)	4.0E-4 lb/MMBtu or 4.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit - non-continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E-4 lb/MMBtu or 7.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E-2 lb/GWh	
	Beryllium (Be)	6.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E-2 lb/GWh	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E-1 lb/GWh	

	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E-1 lb/GWh	
	Mercury (Hg)	4.0E-2 lb/TBtu or 4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < $^1/_2$ the standard.
	b. Hydrogen chloride (HCl)	2.0E-4 lb/MMBtu or 2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E-5 lb/MMBtu or 5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	8.0E-3 lb/MMBtu or 9.0E-2 lb/MWh[2]	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-5 lb/MMBtu or 6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	

	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 7.0E-3 lb/GWh	
	Arsenic (As)	3.0E-1 lb/TBtu or 5.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-2 lb/TBtu or 5.0E-4 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 4.0E-3 lb/GWh	
	Chromium (Cr)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E-2 lb/GWh	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E-1 lb/GWh	
	Selenium (Se)	1.2E0 lb/Tbtu or 2.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	5.0E-3 lb/MMBtu or 8.0E-2 lb/MWh	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	3.0E-1 lb/MMBtu or 2.0E0 lb/MWh	SO_2 CEMS.

	c. Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
7. Eastern Bituminous Coal Refuse (EBCR)-fired unit	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh[2]	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run if using PM CEMS for compliance. For all other compliance demonstration options, collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	

	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh	For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 (Reapproved 2010)[3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	6E-1 lb/MMBtu or 9E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A-8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
		OR	
		1.0E0 lb/TBtu or 1.1E-2 lb/GWh	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of 2.
[2] Gross output.
[3] Incorporated by reference, *see* § 63.14.
[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

*   *   *   *   *

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs
As stated in § 63.9991, you must comply with the applicable operating limits:

If you demonstrate compliance using . . .	You must meet these operating limits . . .
PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements
As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:[1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using . . .[2]
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.

		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Methods 5 or 5I at appendix A-3 to part 60 of this chapter. For positive pressure fabric filters, Method 5D at appendix A-3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 or 5I front half temperature shall be 160° ±14 °C (320° ±25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	PM CEMS	a. Install, certify, operate, and maintain the PM CEMS	Performance Specification 11 at appendix B to part 60 of this chapter and Procedure 2 at appendix F to part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or

		concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	calculate using mass emissions rate and gross output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as	Method 29 at appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.

		the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture	Method 4 at appendix A-3 to part 60 of this chapter.

		content of the stack gas	
		e. Measure the HCl and HF emissions concentrations	Method 26 or Method 26A at appendix A-8 to part 60 of this chapter or Method 320 at appendix A to part 63 of this chapter or ASTM D6348-03[3] with
			(1) the following conditions when using ASTM D6348-03:
			(A) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory;
			(B) For ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);
			(C) For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% ≥R ≤130%; and
			(D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation: $\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} x$
			(2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit.
			Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and	Appendix B of this subpart.

		maintain the HCl or HF CEMS	
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]

		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter, ASTM D6784,[3] or Method 29 at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	Hg CEMS	a. Install, certify, operate, and maintain the CEMS	Sections 3.2.1 and 5.1 of appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of appendix A to this subpart.
	OR	OR	

	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of appendix A to this subpart.
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G, or 2H at appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentratio	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981,[3] or diluent gas monitoring systems certified according to part 75 of this chapter.

		ns of the stack gas	
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.,* per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.
5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and § 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).

		monitoring systems	
		c. Convert hourly emissions concentrations to 30-boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).

[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and 63.10021(h).
[2] See tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.
[3] Incorporated by reference, see § 63.14.

Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits
As stated in § 63.10007, you must comply with the following requirements for establishing operating limits.

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an EGU	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1)	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal)	Data from the PM CPMS and the PM or HAP metals performance tests	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained

				during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance
As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in table 2	Calculating the results of the testing in units of the applicable emissions standard.

5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup	Operating in accordance with table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown	Operating in accordance with table 3.

Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

In accordance with § 63.10031, you must meet the following reporting requirements, as they apply to your compliance strategy.

You must submit the following reports . . .
1. The electronic reports required under § 63.10031 (a)(1), if you continuously monitor Hg emissions.
2. The electronic reports required under § 63.10031 (a)(2), if you continuously monitor HCl and/or HF emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
3. The electronic reports required under § 63.10031(a)(3), if you continuously monitor PM emissions.
Reporting of hourly PM emissions data using ECMPS shall begin with the first operating hour after: January 1, 2024, or the hour of completion of the initial PM CEMS correlation test, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
4. The electronic reports required under § 63.10031(a)(4), if you elect to use a PM CPMS.
Reporting of hourly PM CPMS response data using ECMPS shall begin with the first operating hour after January 1, 2024, or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
5. The electronic reports required under § 63.10031(a)(5), if you continuously monitor SO_2 emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
6. PDF reports for all performance stack tests completed prior to January 1, 2024 (including 30- or 90-boiler operating day Hg LEE test reports and PM test reports to set operating limits for PM CPMS), according to the introductory text of §§ 63.10031(f) and 63.10031(f)(6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.

For a PM test that is used to set an operating limit for a PM CPMS, the report must also include the information in § 63.10023(b)(2)(vi).
For each performance stack test completed on or after January 1, 2024, submit the test results in the relevant quarterly compliance report under § 63.10031(g), together with the applicable reference method information in sections 17 through 31 of appendix E to this subpart.
7. PDF reports for all RATAs of Hg, HCl, HF, and/or SO_2 monitoring systems completed prior to January 1, 2024, and for correlation tests, RRAs and/or RCAs of PM CEMS completed prior to January 1, 2024, according to § 63.10031(f)(1) and (6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For each SO_2 or Hg system RATA completed on or after January 1, 2024, submit the electronic test summary required by appendix A to this subpart or part 75 of this chapter (as applicable) together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart, either prior to or concurrent with the relevant quarterly emissions report.
For each HCl or HF system RATA, and for each correlation test, RRA, and RCA of a PM CEMS completed on or after January 1, 2024, submit the electronic test summary in accordance with section 11.4 of appendix B to this subpart or section 7.2.4 of appendix C to this part, as applicable, together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart.
8. Quarterly reports, in PDF files, that include all 30-boiler operating day rolling averages in the reporting period derived from your PM CEMS, approved HAP metals CMS, and/or PM CPMS, according to §§ 63.10031(f)(2) and (6). These reports are due no later than 60 days after the end of each calendar quarter.
The final quarterly rolling averages report in PDF files shall cover the fourth calendar quarter of 2023.
Starting with the first quarter of 2024, you must report all 30-boiler operating day rolling averages for PM CEMS, approved HAP metals CMS, PM CPMS, Hg CEMS, Hg sorbent trap systems, HCl CEMS, HF CEMS, and/or SO_2 CEMS (or 90-boiler operating day rolling averages for Hg systems), in a format specified by the Administrator, in the quarterly compliance reports required under § 63.10031(g).
If your EGU or common stack is in an averaging plan, each quarterly compliance report must identify the EGUs in the plan and include all of the 30- or 90- group boiler operating day WAERs for the averaging group.
The quarterly compliance reports must be submitted no later than 60 days after the end of each calendar quarter.
9. The semiannual compliance reports described in § 63.10031(c) and (d), in PDF files, according to §§ 63.10031(f)(4) and (6). The due dates for these reports are specified in § 63.10031(b).
The final semiannual compliance report shall cover the period from July 1, 2023, through December 31, 2023.
10. Notifications of compliance status, in PDF files, according to §§ 63.10031(f)(4) and (6) until December 31, 2023, and according to § 63.10031(h) thereafter.

11. Quarterly electronic compliance reports, in accordance with § 63.10031(g), starting with a report for the first calendar quarter of 2024. The reports must be in a format specified by the Administrator and must include the applicable data elements in sections 2 through 13 of appendix E to this subpart.
These reports are due no later than 60 days after the end of each calendar quarter.
12. Quarterly reports, in PDF files, that include the applicable information in §§ 63.10031(c)(5)(ii) and 63.10020(e) pertaining to startup and shutdown events, starting with a report for the first calendar quarter of 2024, if you have elected to use paragraph 2 of the definition of startup in § 63.10042 (see § 63.10031(i)). On or after January 2, 2025, you may not use paragraph 2 of the definition of startup in § 63.10042.
These PDF reports shall be submitted no later than 60 days after the end of each calendar quarter, along with the quarterly compliance reports required under § 63.10031(g).
13. A test report for the PS 11 correlation test of your PM CEMS, in accordance with § 63.10031(j).
If, prior to November 9, 2020, you have begun using a certified PM CEMS to demonstrate compliance with this subpart, use the ECMPS reporting tool to submit the report, in a PDF file, no later than 60 days after that date.
For correlation tests completed on or after November 9, 2020, but prior to January 1, 2024, submit the report, in a PDF file, no later than 60 days after the date on which the test is completed.
For correlation tests completed on or after January 1, 2024, submit the test results electronically, according to section 7.2.4 of appendix C to this subpart, together with the applicable reference method data in sections 17 through 31 of appendix E to this subpart.
14. Quarterly reports that include the QA/QC activities for your PM CPMS or approved HAP metals CMS (as applicable), in PDF files, according to § 63.10031(k).
The first report shall cover the first calendar quarter of 2024, if the PM CPMS or HAP metals CMS is in use during that quarter. Otherwise, reporting begins with the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance.
These reports are due no later than 60 days after the end of each calendar quarter.

19. Amend appendix A to Subpart UUUUU of part 63 by revising sections 7.1.1.2.1, 7.2.3.3, 7.2.4, and 7.2.5.1 to read as follows:

Appendix A to Subpart UUUUU of Part 63—Hg Monitoring Provisions

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7. Recordkeeping and Reporting

*   *   *   *   *

7.1.1.2.1 ***Electronic***. The electronic monitoring plan records must include the following: unit or stack ID number(s); monitoring location(s); the Hg monitoring methodologies used; emissions controls; Hg monitoring system information, including, but not limited to: Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate Hg emissions; and Hg monitor span and range information. The electronic monitoring plan shall be evaluated and submitted using the ECMPS reporting tool provided by the EPA.

* * * * *

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS reporting tool. Hard copy portions of the monitoring plan shall be kept on record according to section 7.1 of this appendix.

7.2.4 ***Certification, Recertification, and Quality-Assurance Test Reporting.*** Except for daily QA tests of the required monitoring systems (i.e., calibration error tests and flow monitor interference checks), the results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.9.1 through 7.1.9.7 of this section (except for test results previously submitted, e.g., under the ARP) shall be submitted electronically, using the ECMPS reporting tool, either prior to or concurrent with the relevant quarterly electronic emissions report.

* * * * *

7.2.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.9984, the owner or operator of any affected unit shall use the ECMPS reporting tool to submit electronic quarterly reports to the Administrator, in a format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) under this subpart.

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20. Amend appendix B to Subpart UUUUU of part 63 by revising sections 10.1.1.2, 11.3.3, 11.4, and 11.5.1 to read as follows:

Appendix B to Subpart UUUUU of Part 63 –HCl and HF Monitoring Provisions

*   *   *   *   *

10. Recordkeeping Requirements

*   *   *   *   *

10.1.1.2 ***Contents of the Monitoring Plan***. For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under § 75.53 (g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPS reporting tool.

*   *   *   *   *

11. Reporting Requirements

*   *   *   *   *

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS reporting tool. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

11.4 ***Certification, Recertification, and Quality-Assurance Test Reporting Requirements***. Except for daily QA tests (i.e., calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS reporting tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically. Submit the test results either prior to or concurrent with the relevant quarterly electronic emissions report. However, for RATAs of the HCl monitor, if this is not possible, you have up to 60 days after the test completion date to submit the test results; in this case, you may claim provisional status for the emissions data affected by the test, starting from the date and hour in which the test was completed and continuing until the date and hour in which the test results are submitted. If the test is successful, the status of the data in that time period changes from provisional to quality-assured, and no further action is required. However, if the test is unsuccessful, the provisional data must be invalidated and resubmission of the affected emission report(s) is required.

* * * * *

11.5.1 The owner or operator of any affected unit shall use the ECMPS reporting tool to submit electronic quarterly reports to the Administrator in a format specified by the Administrator, for each affected unit (or group of units monitored at a common stack). If the certified HCl or HF CEMS is used for the initial compliance demonstration, HCl or HF emissions reporting shall begin with the first operating hour of the 30-boiler operating day compliance demonstration period. Otherwise, HCl or HF emissions reporting shall begin with the first operating hour after successfully completing all required certification tests of the CEMS.

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21. Amend appendix C to Subpart UUUUU of part 63 by:

a. Revising sections 1.2, 1.3, and 4.1;

b. Removing and reserving sections 4.1.1.1 and 4.2.3; and

c. Revising sections 5.1.4, 7.1.1.2.1, 7.2.3.3, 7.2.4, and 7.2.5.1.

The revisions read as follows:

Appendix C to Subpart UUUUU of Part 63—PM Monitoring Provisions

1. General Provisions

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1.2 ***Initial Certification and Recertification Procedures.*** You, as the owner or operator of an affected EGU that uses a PM CEMS to demonstrate compliance with a filterable PM emissions limit in table 1 or 2 to this subpart must certify and, if applicable, recertify the CEMS according to Performance Specification 11 (PS–11) in appendix B to part 60 of this chapter.

1.3 ***Quality Assurance and Quality Control Requirements.*** You must meet the applicable quality assurance requirements of Procedure 2 in appendix F to part 60 of this chapter.

* * * * *

4. Certification and Recertification Requirements

4.1 ***Certification Requirements.*** You must certify your PM CEMS and the other CMS used to determine compliance with the applicable emissions standard before the PM CEMS can be used to provide data under this subpart. Redundant backup monitoring systems (if used) are subject to the same certification requirements as the primary systems.

4.1.1.1. [Reserved]

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4.2.3. [Reserved]

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5. Ongoing Quality Assurance (QA) and Data Validation

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5.1.4 RCA and RRA Acceptability. The results of your RRA or RCA are considered acceptable provided that the criteria in section 10.4(5) of Procedure 2 in appendix F to part 60 of this chapter are met for an RCA or section 10.4(6) of Procedure 2 in appendix F to part 60 of this chapter are met for an RRA.

* * * * *

7. Recordkeeping and Reporting

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7.1.1.2.1 Electronic. Your electronic monitoring plan records must include the following information: Unit or stack ID number(s); unit information (type of unit, maximum rated heat input, fuel type(s), emission controls); monitoring location(s); the monitoring methodologies used; monitoring system information, including (as applicable): Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; operating range and load information; monitor span and range information; units of measure of your PM concentrations (see section 3.2.2); and appropriate default values. Your electronic monitoring plan shall be evaluated and submitted using the ECMPS reporting tool provided by the EPA.

*   *   *   *   *

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS reporting tool. Hard copy portions of the monitoring plan shall be submitted to the appropriate delegated authority.

7.2.4 Certification, Recertification, and Quality-Assurance Test Reporting. Except for daily quality assurance tests of the required monitoring systems (i.e., calibration error or drift tests, sample volume checks, system optics checks, and flow monitor interference checks), you must submit the results of all required certification, recertification, and quality-assurance tests described in sections 7.1.9.1 through 7.1.9.6 and 7.1.10 of this appendix electronically (except for test results previously submitted, e.g., under the Acid Rain Program), using the ECMPS reporting tool. Submit the results of the quality assurance test (i.e., RCA or RRA) or, if applicable, a new PM CEMS correlation test, either prior to or concurrent with the relevant quarterly electronic emissions report. If this is not possible, you have up to 60 days after the test completion date to submit the test results; in this case, you may claim provisional status for the emissions data affected by the quality assurance test or correlation, starting from the date and hour in which the test was completed and continuing until the date and hour in which the test results are submitted. For an RRA or RCA, if the applicable audit specifications are met, the status of the emissions data in the relevant time period changes from provisional to quality-assured, and no further action is required. For a successful correlation test, apply the correlation equation retrospectively to the raw data to change the provisional status of the data to quality-assured, and resubmit the affected emissions report(s). However, if the applicable performance specifications are not met, the provisional data must be invalidated, and resubmission of the affected quarterly emission report(s) is required. For a failed RRA or RCA, you must take corrective actions and proceed according to the applicable requirements found in sections 10.5 through 10.7 of Procedure 2 until a successful quality assurance test report is submitted. If a correlation test is unsuccessful, you may not report quality-assured data from the PM CEMS until the results of a subsequent correlation test show that the specifications in section 13.0 of PS 11 are met.

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7.2.5.1 For each affected EGU (or group of EGUs monitored at a common stack), the owner or operator must use the ECMPS reporting tool to submit electronic quarterly emissions reports to the Administrator, in a format specified by the Administrator, starting with a report for the later of:

* * * * *

22. Amend appendix D to Subpart UUUUU of part 63 by removing introductory text to the appendix and revising sections 3.1.1.2, 3.2.3.3, 3.2.4.1, 3.2.5, and 3.2.5.1 to read as follows:

Appendix D to Subpart UUUUU of Part 63—PM CPMS Monitoring Provisions

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3. RECORDKEEPING AND REPORTING

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3.1.1.2 In addition to the site-specific monitoring plan required under § 63.10000(d), you must use the ECMPS reporting tool to prepare and maintain an electronic monitoring plan for your PM CPMS.

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3.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS reporting tool.

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3.2.4.1 For each affected EGU (or group of EGUs monitored at a common stack) that is subject to the provisions of this appendix, reporting of hourly responses from the PM CPMS will begin either with the first operating hour in the third quarter of 2023 or the first operating hour after completion of the initial stack test that establishes the operating limit, whichever is later. The owner or operator must then use the ECMPS reporting tool to submit electronic quarterly reports to the Administrator, in a format specified by the Administrator, starting with a report for the later of:

* * * * *

3.2.5 Performance Stack Test Results. You must use the ECMPS reporting tool to report the results of all performance stack tests conducted to document compliance with the applicable emissions limit in table 1 or table 2 to this subpart, as follows:

3.2.5.1 Report a summary of each test electronically, in a format specified by the Administrator, in the relevant quarterly compliance report under § 63.10031(g); and

* * * * *

23. Amend appendix E to Subpart UUUUU of part 63 by revising sections 1.0, 15.2, 16.0 through 16.4, 17.0, 19.0, 20.0, and 31.0 to read as follows:

Appendix E to Subpart UUUUU of Part 63—Data Elements

1.0 You must record the electronic data elements in this appendix that apply to your compliance strategy under this subpart. The applicable data elements in sections 2 through 13 of this appendix must be reported in the quarterly compliance reports required under § 63.10031(g), in a format specified by the Administrator, starting with a report that covers the first quarter of 2024. For stack tests used to demonstrate compliance, RATAs, PM CEMS correlations, RRAs and RCAs that are completed on and after January 1, 2024, the applicable data elements in sections 17 through 30 of this appendix must be reported in an XML format prescribed by the Administrator, and the information in section 31 of this appendix must be reported in as one or more PDF files.

* * * * *

15.2 For each RATA, PM CEMS correlation, RRA, or RCA, when you use the ECMPS reporting tool to report the test results as required under appendix A, B, or C to this subpart or, for SO2 RATAs under part 75 of this chapter, you must submit along with the test results, the data elements in sections 17 and 18 of this appendix and, for each test run, the data elements in sections 19 through 30 of this appendix that are associated with the reference method(s) used.

* * * * *

16.0 ***Applicable Reference Methods.*** One or more of the following EPA reference methods is needed for the tests described in sections 14.1 through 14.3 of this appendix: Method 1, 2, 3A, 4, 5, 5D, 5I, 6C, 26, 26A, 29, and/or 30B.

16.1 Application of EPA test Methods 1 and 2. If you use periodic stack testing to comply with an *output-based* emissions limit, you must determine the stack gas flow rate during each performance test run in which EPA test Method 5, 5D, 5I, 26, 26A, 29, or 30B is used, in order to convert the measured pollutant concentration to units of the standard. For EPA test Methods 5, 5D, 5I, 26A and 29, which require isokinetic sampling, the delta-P readings made with the pitot tube and manometer at the EPA test Method 1 traverse points, taken together with measurements of stack gas temperature, pressure, diluent gas concentration (from a separate EPA test Method 3A or 3B test) and moisture, provide the necessary data for the EPA test Method 2 flow rate calculations. Note that even if you elect to comply with a *heat input-based* standard, when EPA test Method 5, 5D, 5I, 26A, or 29 is used, you must still use EPA test Method 2 to determine the average stack gas velocity (v_s), which is needed for the percent isokinetic calculation. The EPA test Methods 26 and 30B do not require isokinetic sampling; therefore, when either of these methods is used, if the stack gas flow rate is needed to comply with the applicable *output-based* emissions limit, you must make a separate EPA test Method 2 determination during each test run.

16.2 Application of EPA test Method 3A. If you elect to perform periodic stack testing to comply with a *heat input-based* emissions limit, a separate measurement of the diluent gas (CO_2 or O_2) concentration is required for each test run in which EPA test Method 5, 5D, 5I, 26, 26A, 29, or 30B is used, in order to convert the measured pollutant concentration to units of the standard. The EPA test Method 3A is the preferred CO_2 or O_2 test method, although EPA test Method 3B may be used instead. Diluent gas measurements are also needed for stack gas molecular weight determinations when using EPA test Method 2.

16.3 Application of EPA test Method 4. For performance stack tests, depending on which equation is used to convert pollutant concentration to units of the standard, measurement of the stack gas moisture content, using EPA test Method 4, may also be required for each test run. The EPA test Method 4 moisture data are also needed for the EPA test Method 2 calculations (to determine the molecular weight of the gas) and for the RATA of an Hg CEMS that measures on a wet basis, when EPA test Method 30B is used. Other applications that require EPA test Method 4 moisture determinations include: RATAs of an SO_2 monitor, when the reference method and CEMS data are measured on a different moisture basis (wet or dry); conversion of wet-basis pollutant concentrations to the units of a *heat input-based* emissions limit when certain EPA test Method 19 equations are used (e.g., Eq. 19-3, 19-4, or 19-8); and stack gas molecular weight determinations. When EPA test Method 5, 5D, 5I, 26A, or 29 is used for the performance test, the EPA test Method 4 moisture determination may be made by using the water collected in the impingers together with data from the dry gas meter; alternatively, a separate EPA test Method 4 determination may be made. However, when EPA test Method 26 or 30B is used, EPA test Method 4 must be performed separately.

16.4 Applications of EPA test Methods 5, 5D, and 5I. The EPA test Method 5 (or, if applicable, 5D or 5I) must be used for the following applications: To demonstrate compliance with a filterable PM emissions limit; for PM tests used to set operating limits for PM CPMS; and for the initial correlations, RRAs and RCAs of a PM CEMS.

* * * * *

17.0 ***Facility and Test Company Information***. In accordance with 40 CFR 63.7(e)(3), a test is defined as three or more runs of one or more EPA Reference

Method(s) conducted to measure the amount of a specific regulated pollutant, pollutants, or surrogates being emitted from a particular EGU (or group of EGUs that share a common stack), and to satisfy requirements of this subpart. On or after January 1, 2024, you must report the data elements in sections 17 and 18, each time that you complete a required performance stack test, RATA, PM CEMS correlation, RRA, or RCA at the affected EGU(s), using EPA test Method 5, 5B, 5D, 5I, 6C, 26, 26A, 29, or 30B. You must also report the applicable data elements in sections 19 through 25 of this appendix for each test. If any separate, corresponding EPA test Method 2, 3A, or 4 test is conducted in order to convert a pollutant concentration to the units of the applicable emission standard given in table 1 or table 2 of this subpart or to convert pollutant concentration from wet to dry basis (or vice-versa), you must also report the applicable data elements in sections 26 through 31 of this appendix.

The applicable data elements in sections 17 through 31 of this appendix must be submitted separately, in XML format, along with the quarterly Compliance Report (for stack tests) or along with the electronic test results submitted to the ECMPS reporting tool (for CMS performance evaluations). The Electronic Reporting Tool (ERT) or an equivalent schema can be utilized to create this XML file. Note: Ideally, for all of the tests completed at a given facility in a particular calendar quarter, the applicable data elements in sections 17 through 31 of this appendix should be submitted together in one XML file. However, as shown in table 8 to this subpart, the timelines for submitting stack test results and CMS performance evaluations are not identical. Therefore, for calendar quarters in which both types of tests are completed, it may not be possible to submit the applicable data elements for all of those tests in a single XML file; separate submittals may be necessary to meet the applicable reporting deadlines.

* * * * *

19.0 ***Run-Level and Lab Data Elements for EPA test Methods 5, 5B, 5D, 5I, 26A, and 29.*** You must report the appropriate Source ID (i.e., Data Element 18.1) and the following data elements, as applicable, for each run of each performance stack test, PM CEMS correlation test, RATA, RRA, or RCA conducted using isokinetic EPA test Method 5, 5B, 5D, 5I, or 26A. If your EGU is oil-fired and you use EPA test Method 26A to conduct stack tests for both HCl and HF, you must report these data elements separately for each pollutant. When you use EPA test Method 29 to measure the individual HAP metals, total filterable HAP metals and total HAP metals, report only the run-level data elements (19.1, 19.3 through 19.30, and 19.38 through 19.41), and the point-level and lab data elements in sections 20 and 21 of this appendix:

* * * * *

20.0 ***Point-Level Data Elements for EPA test Methods 5, 5B, 5D, 5I, 26A, & 29.*** To link the point-level data with the run data in the xml schema, you must report the Source ID (i.e., Data Element 18.1), EPA Test Method (Data Element 19.3), Run Number (Data Element 19.4), and Run Begin Date (Data Element 19.8) with the following point-level data elements for each run of each performance stack test, PM CEMS correlation test, RATA, RRA, or RCA conducted using isokinetic EPA test Method 5, 5B, 5D, 5I, 26A, or 29. Note that these data elements are required for all EPA test Method 29 applications, whether the method is being used to measure the total or individual HAP metals concentrations:

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31.0 ***Other Information for Each Test or Test Series.*** You must provide each test included in the data file described in this appendix with supporting documentation, in a PDF file submitted concurrently with the file, such that all the data required to be reported by 40 CFR 63.7(g) are provided. That supporting data include but are not limited to diagrams showing the location of the test site and the sampling points, laboratory report(s) including analytical calibrations, calibrations of source sampling equipment, calibration gas cylinder certificates, raw instrumental data, field data sheets, quality assurance data (e.g., field recovery spikes) and any required audit results and stack testers' credentials (if applicable). The applicable data elements in § 63.10031(f)(6)(i) through (xii) of this section must be entered into the ECMPS reporting tool with each PDF submittal; the test number(s) (see § 63.10031(f)(6)(xi)) must be included. The test number(s) must match the test number(s) in sections 19 through 31 of this appendix (as applicable).