ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2018–0794; FRL–6716.3–01–OAR]

RIN 2060–AV53

National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The EPA is proposing to amend the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs), commonly known as the Mercury and Air Toxics Standards (MATS). Specifically, the EPA is proposing to amend the surrogate standard for non-mercury (Hg) metal HAP (filterable particulate matter (fPM)) for existing coal-fired EGUs; the fPM compliance demonstration requirements; the Hg standard for lignite-fired EGUs; and the definition of startup. These proposed amendments are the result of the EPA's review of the May 22, 2020 residual risk and technology review (RTR) of MATS.

DATES:

Comments. Comments must be received on or before June 23, 2023. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before May 24, 2023.

Public hearing. The EPA will hold a virtual public hearing on May 9, 2023. See **SUPPLEMENTARY INFORMATION** for information on requesting and registering for a public hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2018–0794, by any of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov/* (our preferred method). Follow the online instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2018–0794 in the subject line of the message.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2018–0794.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2018–0794, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m.–4:30 p.m., Monday–Friday (except federal holidays).

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov/,* including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Sarah Benish, Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5620; and email address: *benish.sarah@epa.gov.*

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. The public hearing will be held via virtual platform on May 9, 2023 and will convene at 11 a.m. Eastern Time (ET) and conclude at 7 p.m. ET. If the EPA receives a high volume of registrations for the public hearing, we may continue the public hearing on May 10, 2023. The EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. The EPA will announce further details at *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.*

The EPA will begin pre-registering speakers for the hearing no later than 1 business day following publication of this document in the **Federal Register**. The EPA will accept registrations on an individual basis. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards* or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.* The last day to pre-register to speak at the hearing will be May 8, 2023. Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers in approximate order at: *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.*

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony by submitting the text of your oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.* While the EPA expects the hearing to go forward as described in this section, please monitor our website or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of an interpreter or special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by May 1, 2023. The EPA may not be able to arrange accommodations without advanced notice.

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2018–0794.[1] All documents in the docket are listed in *https://www.regulations.gov/.* Although listed, some information is not publicly available, *e.g.,* Confidential Business

[1] As explained in a memorandum to the docket, the docket for this action includes the documents and information, in whatever form, in Docket ID Nos. EPA–HQ–OAR–2009–0234 (National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-fired Electric Utility Steam Generating Units), EPA–HQ–OAR–2002–0056 (National Emission Standards for Hazardous Air Pollutants for Utility Air Toxics; Clean Air Mercury Rule (CAMR)), and Legacy Docket ID No. A–92–55 (Electric Utility Hazardous Air Pollutant Emission Study). See memorandum titled *Incorporation by reference of Docket Number EPA–HQ–OAR–2009–0234, Docket Number EPA–HQ–OAR–2002–0056, and Docket Number A–92–55 into Docket Number EPA–HQ–OAR–2018–0794* (Docket ID Item No. EPA–HQ–OAR–2018–0794–0005).

Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. With the exception of such material, publicly available docket materials are available electronically in *Regulations.gov*.

Instructions. Direct your comments to Docket ID No. EPA–HQ–OAR–2018–0794. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *https://www.regulations.gov/,* including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit electronically to *https://www.regulations.gov/* any information that you consider to be CBI or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed in the *Submitting CBI* section of this document.

The EPA may publish any comment received to its public docket. Multimedia submissions (audio, video, *etc.*) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the Web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

The *https://www.regulations.gov/* website allows you to submit your comment anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *https://www.regulations.gov/,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *https://www.epa.gov/dockets.*

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov/.* Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, note the Docket ID No., mark the outside of the digital storage media as CBI, and identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Instructions* section of this document. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI and note the Docket ID No. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described above, should include clear CBI markings and note the Docket ID No. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, or if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link. If sending CBI information through the postal service, please send it to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2018–0794. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

Preamble acronyms and abbreviations. Throughout this document the use of ''we,'' ''us,'' or ''our'' is intended to refer 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:

Btu British Thermal Units
CAA Clean Air Act
CBI Confidential Business Information
CEMS continuous emissions monitoring systems
CFR Code of Federal Regulations
CO_2 carbon dioxide
CPMS continuous parameter monitoring system
EAV equivalent annualized value
ECMPS Emissions Collection and Monitoring Plan System
EGU electric utility steam generating unit
EIA Energy Information Administration
EJ environmental justice
EPA Environmental Protection Agency
ESP electrostatic precipitator
FF fabric filter
FGD flue gas desulfurization
fPM filterable particulate matter
GWh gigawatt-hour
HAP hazardous air pollutant(s)
HCl hydrogen chloride
HF hydrogen fluoride
Hg mercury
Hg^0 elemental Hg vapor
HQ hazard quotient
IGCC integrated gasification combined cycle
IPM Integrated Planning Model
lb Pounds
LEE low emitting EGU
MACT maximum achievable control technology
MATS Mercury and Air Toxics Standards
MM million
MW megawatt
NAICS North American Industry Classification System
NEEDS National Electric Energy Data System
NESHAP National Emission Standards for Hazardous Air Pollutants
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
PDF Portable Document Format
PM particulate matter
ppm parts per million
PV present value
RIA regulatory impact analysis
RTR residual risk and technology review
SC–CO_2 social cost of carbon
SO_2 sulfur dioxide
tpy tons per year
TBtu trillion British thermal units
WebFIRE Web Factor Information Retrieval System

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

I. Executive Summary

A. Background and Purpose of the Regulatory Action

Exposure to hazardous air pollution (''HAP,'' sometimes known as toxic air pollution, including Hg, chromium, arsenic, and lead) can cause a range of adverse health effects including harming people's central nervous system; damage to their kidneys; and cancer. Recognizing the dangers posed by HAP, Congress enacted Clean Air Act (CAA) section 112. Under CAA section 112, the EPA is required to set standards (known as ''MACT'' (maximum achievable control technology) standards) for major sources of HAP that ''require the maximum degree of reduction in emissions of the hazardous air pollutants . . . (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable.'' 42 U.S.C. 7412(d)(2). To ensure a minimum level (or ''floor'') of emissions reductions, Congress required that MACT standards for existing sources ''shall not be less stringent than . . . the average emission limitation achieved by the best performing 12 percent of existing sources''; and MACT standards for new sources ''shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source[.]'' 42 U.S.C. 7412(d)(3). These requirements effectively obligated all sources to reduce emissions as well as the best sources in their category. Congress did not stop there, however. First, it required the EPA, 8 years after setting the standard, to address any residual risks posed by the source category (called the ''residual risk review''). Second, and as explained in more detail below, it required the EPA, at least every 8 years on an ongoing basis, to review and revise as necessary the MACT standard taking into account developments in practices, processes and control technologies (called the ''technology review''). For EGUs, Congress also required the EPA to make a one-time determination of whether it is ''appropriate and necessary'' to regulate this source category under CAA section 112. The EPA found regulation of EGUs ''appropriate and necessary'' in 2000 and reaffirmed that finding in 2012 and 2016. MACT standards were originally set for EGUs in 2012, and those standards remain in place today. In 2020, the EPA conducted the 8-year residual risk and technology review and determined not to update the MACT standard.

On January 20, 2021, President Biden signed Executive Order 13990, ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis'' (86 FR 7037; January 25, 2021). The Executive order, among other things, instructed the EPA to review the 2020 final rule titled, ''National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review'' (85 FR 31286; May 22, 2020) (2020 Final Action) and to consider publishing a notice of proposed rulemaking suspending, revising, or rescinding that action. The 2020 Final Action included a finding that it is not appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 as well as the RTR for the MATS rule. The results of the EPA's review of the 2020 appropriate and necessary finding were proposed on February 9, 2022 (87 FR 7624) (2022 Proposal) and finalized on March 6, 2023 (88 FR 13956). In the 2022 Proposal, the EPA also solicited information on the performance and cost of new or improved technologies that control hazardous air pollutant (HAP) emissions, improved methods of operation, and risk-related information to further inform the EPA's review of the 2020 MATS RTR. This action presents the proposed results of the EPA's review of the MATS RTR.

In particular, with respect to the standard for fPM (as a surrogate for non-Hg metals), and the standard for Hg from EGUs that burn lignite coal, the EPA proposes to conclude that developments since 2012—and in particular the fact that the majority of sources are vastly outperforming the MACT standards with control technologies that are cheaper and more effective than the EPA forecast while a smaller number of sources' performance lags behind—warrant strengthening these standards. While the 2012 MATS drove critical HAP reductions at much lower cost than estimated, coal-fired EGUs still emit a substantial amount of HAP and developments since 2012 provide opportunities to address these emissions and ensure that all coal-fired EGUs are performing at levels achievable by the fleet. These proposed revisions would ensure that the EPA's standards continue to fulfill Congress's direction to require the maximum degree of reduction of HAP while taking into account the statutory factors.

B. Summary of the Major Provisions of the Regulatory Action

The 2012 MATS Final Rule established emission standards to limit emissions of HAP from coal- and oil-fired EGUs. The rule required that affected sources limit emissions of Hg, of non-Hg metal HAP (*e.g.,* chromium, nickel, arsenic, lead), acid gas HAP (*e.g.,* hydrogen chloride (HCl), hydrogen fluoride (HF), selenium dioxide (SeO_2)), and organic HAP (*e.g.,* formaldehyde, dioxins/furans). Since MATS was promulgated in 2012, power sector emissions of Hg, acid gas HAP, and non-Hg metal HAP have decreased by about 86 percent, 96 percent, and 81 percent, respectively, as compared to 2010 emissions levels (See Table 4 at 84 FR 2689, February 7, 2019). Still, coal- and oil-fired EGUs remain the largest domestic emitter of Hg and many other HAP, including many of the non-Hg HAP metals and HCl. Exposure to these HAP, at certain levels and duration, is associated with a variety of adverse health effects. These adverse health effects may include irritation of the lung, skin, and mucus membranes; detrimental effects on the central nervous system; damage to the kidneys; alimentary effects such as nausea and vomiting; and cancer.[2] See 77 FR 9310 for a fuller discussion of the health effects associated with these pollutants. Three of the key metal HAP emitted by EGUs (inorganic arsenic (As), hexavalent chromium (Cr), and nickel compounds (Ni)) have been classified as human carcinogens, while two others (cadmium (Cd) and selenium (Se)) are classified as probable human carcinogens.[3]

To address emissions of these non-Hg metal HAP, MATS sets individual emission limits for each of the 10 non-Hg metals emitted from coal- and oil-fired EGUs. Alternatively, affected sources may meet an emission standard for ''total non-Hg metals'' by summing the emission rates of each of the non-Hg metals. The MATS rule also allows affected sources to meet a filterable PM (fPM)[4] emission standard as a surrogate for the non-Hg metals. For existing coal-fired EGUs, most units have chosen to demonstrate compliance with the non-Hg metal HAP surrogate fPM emission standard of 3.0E–02 pounds of fPM per million British thermal units of heat input (lb/MMBtu).

CAA section 112(d)(2) directs the EPA to require the maximum degree of HAP emission reductions achievable, taking into account certain considerations, and CAA section 112(d)(3) sets the floor for emission standards based on the reductions achieved by the best performing sources. The MATS was based upon the EPA's analysis under CAA sections 112(d)(2) and (d)(3) in 2012. CAA section 112(d)(6) further requires the EPA, at least every 8 years, to review and revise standards taking into account developments in practices, processes and control technologies. After reviewing developments in the current emission levels of fPM from existing coal-fired EGUs, the costs of control technologies, and the effectiveness of those technologies, as well as the costs of meeting a standard that is more stringent than 3.0E–02 lb/MMBtu and the other statutory factors, the EPA is proposing to revise the non-Hg metal surrogate fPM emission standard for all existing coal-fired EGUs to a more stringent fPM emission standard of 1.0E–02 lb/MMBtu, which is comparable to the MATS new source standard for fPM.[5] The EPA is also soliciting comment on opportunities to revise the MATS fPM emission standard to an even more stringent level of 6.0E–03 lb/MMBtu.

The EPA is also proposing a revision to the requirements for demonstrating compliance with the fPM emission standard. Currently, EGUs that do not qualify for the low emitting EGU (LEE) program can demonstrate compliance with the fPM standard either by conducting quarterly performance testing (*i.e.,* quarterly stack testing) or by using PM continuous emission monitoring systems (PM CEMS). After considering updated information on the costs for quarterly performance testing compared to the costs of PM CEMS and on the measurement capabilities of PM CEMS, as well as other benefits of using PM CEMS, which include increased transparency and accelerated identification of anomalous emissions, the EPA is proposing to require that all coal-fired EGUs demonstrate compliance with the fPM emission standard by using PM CEMS. Accordingly, because almost all regulated sources have chosen to demonstrate compliance with the non-Hg HAP metal standards by demonstrating compliance with the surrogate fPM standard and because of the benefits of PM CEMS use for demonstrating compliance, the EPA is proposing to remove the total and individual non-Hg metals emission limits from MATS. Requiring the use of PM CEMS, if finalized, would also render the current compliance method for the LEE program superfluous, since LEE is an optional stack testing program and the considered fPM limits are both below the current fPM LEE program limit of 1.5E–02 lb/MMBtu (*i.e.,* 50 percent of the current fPM standard). Therefore, the EPA also proposes to remove fPM, as well as the total and individual non-Hg HAP metals, from the LEE program.

The EPA is also proposing to establish a more protective Hg emission standard for existing lignite-fired EGUs. Currently, existing lignite-fired EGUs must meet a Hg emission standard of 4.0E–06 lb/MMBtu[6] or an alternative output-based emission standard of 4.0E–02 pounds of Hg per gigawatt-hour output (lb/GWh). The EPA recently collected information on current Hg emission levels and controls for lignite-fired EGUs from information provided routinely to the EPA and to the Energy Information Administration (EIA) and by using the information collection authority provided under CAA section 114. That information showed developments that demonstrate that lignite-fired EGUs can achieve a Hg emission rate that is much lower than the current standard, and that there are cost-effective control technologies and methods of operation that are available to achieve a more stringent standard. Accordingly, the EPA is proposing that lignite-fired EGUs must meet the same Hg emission standard as EGUs firing other types of coal (*i.e.,* bituminous, and subbituminous) which is 1.2 lb/TBtu or an alternative output-based standard of 1.3E–02 lb/GWh. The EPA is not proposing to revise the current Hg emission standard for existing EGUs firing non-lignite coal.

Finally, the EPA is proposing to remove one of the two options for defining the startup period for MATS-affected EGUs. The first option defines

[2] 77 FR 9310.

[3] U.S. EPA. Table 1. Prioritized Chronic Dose-Response Values for Screening Risk Assessments. Available at: *https://www.epa.gov/fera/dose-response-assessment-assessing-health-risks-associated-exposure-hazardous-air-pollutants.*

[4] Total PM is composed of the filterable PM fraction (fPM) and the condensible PM fraction. In establishing fPM as a surrogate for the non-Hg metal HAP, the EPA explained that most of the non-Hg metal HAP are present overwhelmingly in the fPM fraction. Selenium may be present in both the fPM fraction and/or as the acid gas, SeO_2, in the condensible PM fraction. SeO_2 is an acid gas HAP and is well controlled by the emission limit for acid gas HAP. In addition, using fPM as the surrogate will allow the use of continuous PM monitoring systems, which measure filterable (but not total) PM, thereby providing a more continuous measure of compliance.

[5] The fPM standard for new coal-fired EGU is 9.0E–02 lb/MWh, which is an output-based emission standard. See 78 FR 24073. This emission is equivalent for a new coal-fired EGU with a heat rate of 9.0 MMBtu/MWh (9,000 Btu/kWh).

[6] The emission standard of 4.0E–06 lb/MMBtu is more often written as 4.0 lb/TBtu (pounds of Hg per trillion British thermal units).

startup as either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Under the first option, startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). In the second option, startup is defined as the period in which operation of an EGU is initiated for any purpose, and startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Under the second option, startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on-site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes, whichever is earlier. The EPA is proposing to remove the second option, which is currently being used by fewer than 10 EGUs as discussed in section V.D.1 of this preamble.

The EPA is not proposing to modify the HCl emission standard (nor the alternative sulfur dioxide (SO_2) emission standard), which serves as a surrogate for all acid gas HAP (HCl, HF, SeO_2) for existing coal-fired EGUs. An evaluation of recent compliance data for HCl and/or SO_2 emissions revealed that approximately two-thirds of coal-fired EGUs operate at or below the alternative SO_2 emission standard of 2.0E–01 lb SO_2/MMBtu (SO_2 may be used as an alternative surrogate for acid gas HAP at coal-fired EGUs with operational flue gas desulfurization (FGD) systems and SO_2 CEMS). Approximately one-third of coal-fired EGUs have a SO_2 emission rate above the current SO_2 standard, but instead operate in compliance with the primary acid gas HAP limit for HCl of 2.0E–03 lb HCl/MMBtu, with most using an FGD system and/or by firing coal with low chlorine content and high alkalinity. The EPA did not identify any new technologies or developments in existing technologies that would achieve additional emission reductions. Based on this review, the EPA is not proposing revisions to the acid gas HAP emission standards for coal-fired EGUs.

The EPA is unaware of any new coal- or oil-fired EGUs in development and has not projected any new coal- or oil-fired EGUs in EPA modeling to support various power sector-related rulemakings. For that reason, the EPA has not reviewed and is not proposing any revisions to the MATS new source emission standards. In some cases, however, proposed revisions to existing source emission standards may be more stringent than the corresponding new source emission standard. In those instances, the EPA has addressed that illogical outcome by proposing to revise the corresponding new source standard to be at least as stringent as the proposed revision to the existing source standard.

The EPA is also not proposing to revise MATS emission standards for existing Integrated Gasification Combined Cycle (IGCC) EGUs, nor to the MATS emission standards for any of the subcategories of existing oil-fired EGUs.

In addition to generally soliciting comments on all aspects of this proposed action, the EPA has identified several aspects of the proposal on which comments are specifically requested.

In selecting a proposed standard, as discussed in detail below, the EPA considered the statutory direction and factors laid out by Congress in CAA section 112. Separately, pursuant to E.O. 12866, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, ''Regulatory Impact Analysis for the Proposed 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–23–002), is available in the docket, and is briefly summarized here and in section VI of this preamble.

II. General Information

A. Does this action apply to me?

The source category that is the subject of this proposal is coal- and oil-fired EGUs regulated under 40 CFR part 63, subpart UUUUU. The North American Industry Classification System (NAICS) codes for the coal- and oil-fired EGU industry are 221112, 221122, and 921150. This list of categories and NAICS codes is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that this proposed action is likely to affect. The proposed standards, once promulgated, will be directly applicable to the affected sources. Federal, state, local, and tribal government entities that own and/or operate EGUs subject to 40 CFR part 63, subpart UUUUU would be affected by this proposed action. The coal- and oil-fired EGU source category was added to the list of categories of major and area sources of HAP published under section 112(c) of the CAA on December 20, 2000 (65 FR 79825). CAA section 112(a)(8) defines an EGU as any fossil fuel-fired combustion unit of more than 25 megawatts (MW) that serves a generator that produces electricity for sale. 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 considered an EGU.

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

In addition to being available in the docket, an electronic copy of this action is available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this proposed action 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 of the proposal and key technical documents at this same website.

A memorandum showing the rule edits that would be necessary to incorporate the changes proposed in this action to 40 CFR part 63, subpart UUUUU is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2018–0794). Following signature by the EPA Administrator, the EPA also will post a copy of this document to *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.*

III. Background

A. What is the authority for this action?

1. Statutory Authority

The statutory authority for this action is provided by sections 112 and 301 of the CAA, as amended (42 U.S.C. 7401 *et seq.*). Section 112 of the CAA establishes a multi-stage regulatory process to develop standards for emissions of HAP from stationary sources. Generally, during the first stage Congress directed the EPA to establish technology-based standards to ensure that all sources control pollution at the level achieved by the best-performing sources, referred to as the maximum achievable control technology (MACT). After the first stage, Congress directed the EPA to review those standards periodically to determine whether they should be strengthened. Within 8 years after promulgation of the standards, the EPA must evaluate the MACT standards to determine whether additional standards are needed to address any remaining risk associated with HAP emissions. This second stage is commonly referred to as the ''residual risk review.'' In addition, the CAA also requires the EPA to review standards set under CAA section 112 on an ongoing basis no less than every 8 years and revise the standards as necessary taking into account any ''developments in practices, processes, and control technologies.'' This review is commonly referred to as the ''technology review,'' and is the subject of this proposal. 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. ''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. All other sources are ''area sources.'' For major sources, CAA section 112(d)(2) provides that the technology-based NESHAP must reflect ''the maximum degree of reduction in emissions of the [HAP] subject to this section (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable.'' 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.'' [7] In certain instances, as provided in CAA section 112(h), the EPA may set work practice standards in lieu of numerical emission standards. The EPA must also consider control options that are more stringent than the floor. Standards more stringent than the floor are commonly referred to as ''beyond-the-floor'' standards. For area sources, CAA section 112(d)(5) allows the EPA to set standards based on generally available control technologies or management practices (GACT standards) in lieu of MACT standards.[8]

For categories of major sources and any area source categories subject to MACT standards, the next stage in standard-setting focuses on identifying and addressing any remaining (*i.e.,* ''residual'') risk pursuant to CAA section 112(f)(2). The residual risk review requires the EPA to update standards if needed to provide an ample margin of safety to protect public health.

Concurrent with that review, and then at least every 8 years thereafter, CAA section 112(d)(6) 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).'' *See Portland Cement Ass'n* v. *EPA,* 665 F.3d 177, 189 (D.C. Cir. 2011) (''Though EPA must review and revise standards 'no less often than every eight years,' 42 U.S.C. 7412(d)(6), nothing prohibits EPA from reassessing its standards more often.''). 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. *Natural Resources Defense Council (NRDC)* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008); *Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667 (D.C. Cir. 2013). The EPA may consider cost in deciding whether to revise the standards pursuant to CAA section 112(d)(6). *See e.g., Nat'l Ass'n for Surface Finishing* v. *EPA,* 795 F.3d 1, 11 (D.C. Cir. 2015). The EPA is required to address regulatory gaps, such as missing MACT standards for listed air toxics known to be emitted from the source category. *Louisiana Environmental Action Network (LEAN)* v. *EPA,* 955 F.3d 1088 (D.C. Cir. 2020).

In this action, the EPA is proposing to reconsider the 2020 Final Action's risk and technology review pursuant to the EPA's inherent authority to reconsider previous decisions and to revise, replace, or repeal a decision to the extent permitted by law and supported by a reasoned explanation. *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009); *see also Motor Vehicle Mfrs. Ass'n* v. *State Farm Mutual Auto. Ins. Co.,* 463 U.S. 29, 42 (1983).

2. EGU Regulation Under CAA Section 112

Congress enacted a special provision concerning coal- and oil-fired EGU HAP emission regulations in the 1990 CAA Amendments under section 112(n)(1)(a) of the CAA that is not applicable to other source categories. This provision required the EPA to conduct a study to evaluate the hazards to public health that are reasonably anticipated to occur as a result of HAP emissions from EGUs, and to make a one-time finding of whether to regulate EGUs under CAA section 112 if the EPA found that doing so was ''appropriate and necessary.'' 42 U.S.C. 7412(n)(1)(A) (the ''appropriate and necessary finding''). Once this one-time finding was made, if the decision was to regulate, Congress subjected EGUs to the same standards and procedures as other source categories. *Id.* (''The Administrator shall regulate electric utility steam generating units under this section'' if he finds doing so is ''appropriate and necessary.''); *see also New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008) (establishing that, on the applicability of CAA section 112(c)(9)'s delisting requirements, coal- and oil-fired EGUs are treated similarly as other CAA section 112 regulated sources once listed under CAA section 112(c)).

The EPA originally made the appropriate and necessary finding in 2000. This was followed by a series of affirmations and reversals of this finding, as well as a Supreme Court decision that required the EPA to consider the costs of regulation in making this finding. *See Michigan* v. *EPA,* 576 U.S. 743 (2015). On February 9, 2022, the EPA published a notice of proposed rulemaking reaffirming that it remains appropriate and necessary to regulate HAP, including Hg, from coal- and oil-fired EGUs after considering cost.[9] The EPA's consideration of costs in its decision to reaffirm the appropriate and necessary finding was based on estimated and realized costs from the first stage of CAA section 112 regulation, *i.e.,* establishing MACT-based standards and determining whether additional ''beyond-the-floor'' standards are needed to address remaining risk.

Consistent with Congress's direction, after making the appropriate and necessary finding, the EPA treated EGUs like all other source categories. As required by CAA section 112(d)(2), the EPA first set a floor based on the best 12 percent of performers, and then conducted a beyond-the-floor analysis. That inquiry led to the current MATS, established in 2012. As explained above, the CAA then required the EPA,

[7] Specifically, for existing sources, the MACT ''floor'' shall not be less stringent than the average emission reduction achieved by the best performing 12 percent of existing sources. For new sources MACT shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source.

[8] For categories of area sources subject to GACT standards, there is no requirement to address residual risk, but, similar to the major source categories, the technology review is required.

[9] For further discussion on the history of the CAA section 112(n)(1)(A) appropriate and necessary finding, please refer to the EPA's February 9, 2022 proposal (87 FR 7624).

within 8 years of promulgating the standards, to conduct the residual risk and technology reviews. Congress thus contemplated that well after the EPA determined the regulation of EGUs was appropriate and necessary and well after the EPA set initial standards in accordance with the floor and beyond-the-floor requirements in CAA section 112(d)(2), that at least every 8 years thereafter on a continuing basis, the EPA would review and revise those standards as necessary taking into account developments in practices, processes, and control technologies. The EPA has conducted over 100 technology reviews and has regularly updated emissions standards for HAP based upon the technology review.

3. Executive Order 13990

On January 20, 2021, President Biden signed Executive Order 13990, ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis.'' The Executive order, among other things, instructs the EPA to review the 2020 Final Action titled, ''National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review'' (85 FR 31286; May 22, 2020) and consider publishing a notice of proposed rulemaking suspending, revising, or rescinding that action.

B. What is this source category and how does the current NESHAP regulate its HAP emissions?

The NESHAP for the coal- and oil-fired EGU source category (commonly referred to as MATS) were initially promulgated on February 16, 2012 (77 FR 9304) (2012 MATS Final Rule), under title 40 part 63, subpart UUUUU. The MATS rule was amended on April 19, 2012 (77 FR 23399), to correct typographical errors and certain preamble text that was inconsistent with regulatory text; on April 24, 2013 (78 FR 24073), to update certain emission limits and monitoring and testing requirements applicable to new sources; on November 19, 2014 (79 FR 68777), to revise definitions for startup and shutdown and to finalize work practice standards and certain monitoring and testing requirements applicable during periods of startup and shutdown; and on April 6, 2016 (81 FR 20172), to correct conflicts between preamble and regulatory text and to clarify regulatory text. In addition, the electronic reporting requirements of the rule were amended on March 24, 2015 (80 FR 15510), to allow for the electronic submission of Portable Document Format (PDF) versions of certain reports until April 16, 2017, while the EPA's Emissions Collection and Monitoring Plan System (ECMPS) is revised to accept all reporting that is required by the rule, and on April 6, 2017 (82 FR 16736), and on July 2, 2018 (83 FR 30879), to extend the interim submission of PDF versions of reports through June 30, 2018, and July 1, 2020, respectively.

The MATS rule applies to coal- and oil-fired EGUs located at both major and area sources of HAP emissions. An existing affected source is the collection of coal- or oil-fired EGUs in a subcategory within a single contiguous area and under common control. A new affected source is each coal- or oil-fired EGU for which construction or reconstruction began after May 3, 2011. As previously stated in section II of this preamble, an EGU is a fossil fuel-fired combustion unit of more than 25 MW that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MW electric output to any utility power distribution system for sale is also considered an EGU. The MATS rule defines additional terms for determining rule applicability, including, but not limited to, definitions for ''coal-fired electric utility steam generating unit,'' ''oil-fired electric utility steam generating unit,'' and ''fossil fuel-fired.'' Certain types of electric generating units are not subject to 40 CFR part 63, subpart UUUUU: any unit designated as a major source stationary combustion turbine subject to subpart YYYY of 40 CFR part 63 and any unit designated as an area source stationary combustion turbine, other than an IGCC unit; any EGU that is not a coal- or oil-fired EGU and that meets the definition of a natural gas-fired EGU in 40 CFR 63.10042; any EGU greater than 25 MW that has the capability of combusting either coal or oil, but does not meet the definition of a coal- or oil-fired EGU because it did not fire sufficient coal or oil to satisfy the average annual heat input requirement set forth in the definitions for coal-fired and oil-fired EGUs in 40 CFR 63.10042; and any electric steam generating unit combusting solid waste (*i.e.,* a solid waste incineration unit) subject to standards established under sections 129 and 111 of the CAA.

For coal-fired EGUs, the rule established standards to limit emissions of Hg, acid gas HAP (*e.g.,* HCl, HF), non-Hg HAP metals (*e.g.,* nickel, lead, chromium), and organic HAP (*e.g.,* formaldehyde, dioxin/furan). Emission standards for HCl serve as a surrogate for the acid gas HAP, with an alternate standard for SO_2 that may be used as a surrogate for acid gas HAP for those coal-fired EGUs with FGD systems and SO_2 CEMS installed and operational. Standards for fPM serve as a surrogate for the non-Hg HAP metals, with standards for total non-Hg HAP metals and individual non-Hg HAP metals provided as alternative equivalent standards. Work practice standards limit formation and emissions of organic HAP.

For oil-fired EGUs, the 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 serve as a surrogate for total HAP metals, with standards for total HAP metals and individual HAP metals provided as alternative equivalent standards. Work practice standards limit formation and emissions of organic HAP.

The MATS rule includes standards for existing and new EGUs for seven subcategories: two for coal-fired EGUs, one for IGCC EGUs, one for solid oil-derived fuel-fired EGUs (*i.e.,* petroleum coke-fired), and three for liquid oil-fired EGUs. EGUs in six of the subcategories are subject to numeric emission limits for all the pollutants described above except for organic HAP. Emissions of organic HAP are regulated by a work practice standard that requires periodic combustion process tune-ups. EGUs in the subcategory of limited-use liquid oil-fired EGUs with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input are also subject to a work practice standard consisting of periodic combustion process tune-ups but are not subject to any numeric emission limits. Emission limits for existing EGUs are summarized in Table 1.

TABLE 1—EMISSION LIMITS FOR EXISTING AFFECTED EGUs

Subcategory	Pollutant	Emission limit [1]
Any coal-fired unit firing any rank of coal	a. fPM	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh.
	OR	OR
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.
	OR	OR
	Individual HAP metals:	
	Antimony, Sb	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.
	Arsenic, As	1.1 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	2.8 lb/TBtu or 3.0E–2 lb/GWh.
	Cobalt, Co	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.
	Lead, Pb	1.2 lb/TBtu or 2.0E–2 lb/GWh.
	Manganese, Mn	4.0 lb/TBtu or 5.0E–2 lb/GWh.
	Nickel, Ni	3.5 lb/TBtu or 4.0E–2 lb/GWh.
	Selenium, Se	5.0 lb/TBtu or 6.0E–2 lb/GWh.
	b. HCl	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.
	OR	OR
	SO_2 [2]	2.0E–1 lb/MMBtu or 1.5 lb/MWh.
Coal-fired unit low rank virgin coal	c. Hg	1.2 lb/TBtu or 1.3E–2 lb/GWh.
Coal-fired unit low rank virgin coal	c. Hg	4.0 lb/TBtu or 4.0E–2 lb/GWh.
IGCC unit	a. fPM	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh.
	OR	OR
	Total non-Hg HAP metals	6.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.
	OR	OR
	Individual HAP metals:	
	Antimony, Sb	1.4 lb/TBtu or 2.0E–2 lb/GWh.
	Arsenic, As	1.5 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	2.9 lb/TBtu or 3.0E–2 lb/GWh.
	Cobalt, Co	1.2 lb/TBtu or 2.0E–2 lb/GWh.
	Lead, Pb	1.9E+2 lb/MMBtu or 1.8 lb/MWh.
	Manganese, Mn	2.5 lb/TBtu or 3.0E–2 lb/GWh.
	Nickel, Ni	6.5 lb/TBtu or 7.0E–2 lb/GWh.
	Selenium, Se	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.
	b. HCl	5.0E–4 lb/MMBtu or 5.0E–3 lb/MWh.
	c. Hg	2.5 lb/TBtu or 3.0E–2 lb/GWh.
Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. fPM	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh.
	OR	OR
	Total HAP metals	8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.
	OR	OR
	Individual HAP metals:	
	Antimony, Sb	1.3E+1 lb/TBtu or 2.0E–1 lb/GWh.
	Arsenic, As	2.8 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	5.5 lb/TBtu or 6.0E–2 lb/GWh.
	Cobalt, Co	2.1E+1 lb/TBtu or 3.0E–1 lb/GWh.
	Lead, Pb	8.1 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 1.1 lb/GWh.
	Selenium, Se	3.3 lb/TBtu or 4.0E–2 lb/GWh.
	Hg	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.
	b. HCl	2.0E–3 lb/MMBtu or 1.0E–2 lb/MWh.
	c. HF	4.0E–4 lb/MMBtu or 4.0E–3 lb/MWh.
Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. fPM	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh.
	OR	OR
	Total HAP metals	6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.
	OR	OR
	Individual HAP metals:	
	Antimony, Sb	2.2 lb/TBtu or 2.0E–2 lb/GWh.
	Arsenic, As	4.3 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 1.4 lb/GWh.
	Lead, Pb	4.9 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 4.1 lb/GWh.
	Selenium, Se	9.8 lb/TBtu or 2.0E–1 lb/GWh.

TABLE 1—EMISSION LIMITS FOR EXISTING AFFECTED EGUS—Continued

Subcategory	Pollutant	Emission limit [1]
	Hg	4.0E–2 lb/TBtu or 4.0E–4 lb/GWh.
	b. HCl	2.0E–4 lb/MMBtu or 2.0E–3 lb/MWh.
	c. HF	6.0E–5 lb/MMBtu or 5.0E–4 lb/MWh.
Solid oil-derived fuel-fired unit	a. fPM	8.0E–3 lb/MMBtu or 9.0E–2 lb/MWh.
	OR	OR
	Total non-Hg HAP metals	4.0E–5 lb/MMBtu or 6.0E–1 lb/GWh.
	OR	OR
	Individual HAP metals	
	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	1.1 lb/TBtu or 2.0E–2 lb/GWh.
	Lead, Pb	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.
	Manganese, Mn	2.3 lb/TBtu or 4.0E–2 lb/GWh.
	Nickel, Ni	9.0 lb/TBtu or 2.0E–1 lb/GWh.
	Selenium, Se	1.2 lb/TBtu 2.0E–2 lb/GWh.
	b. HCl	5.0E–3 lb/MMBtu or 8.0E–2 lb/MWh.
	OR	OR
	SO_2 [2]	3.0E–1 lb/MMBtu or 2.0 lb/MWh.
	c. Hg	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.

[1] Units of emission limits:
lb/MMBtu = pounds pollutant per million British thermal units fuel input;
lb/TBtu = pounds pollutant per trillion British thermal units fuel input;
lb/MWh = pounds pollutant per megawatt-hour electric output (gross); and
lb/GWh = pounds pollutant per gigawatt-hour electric output (gross).
[2] Alternate SO_2 limit may be used if the EGU has some form of FGD system and SO_2 CEMS installed.

C. What data collection activities were conducted to support this proposed action?

On February 9, 2022, the EPA published a notice of proposed rulemaking reaffirming that it remains appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 after considering the cost of regulation. In that same action, the EPA solicitated information on the cost and performance of new or improved technologies that control HAP emissions, on improved methods of operation, and on risk-related information to further inform the EPA's assessment of the MATS RTR. Generally, commenters were unaware of new technologies, but indicated that current technologies are more widely used, more effective, and cheaper than at the time of the adoption of MATS. Specific data or information used to support this action are discussed in more detail in section V of this preamble.

The EPA also issued a limited request for information pursuant to section 114 of the CAA to obtain information related to HAP emissions from coal- and oil-fired EGUs to inform the technology review under CAA section 112(d)(6). Specifically, the EPA collected information and data related to Hg emissions and control technologies for lignite-fired EGUs. The CAA section 114 survey and responses are available in the docket for this action.

D. What other relevant background information and data are available?

The EPA used multiple sources of information to support this proposed action. A comprehensive list of facilities and EGUs that are subject to the MATS rule was compiled primarily using the list from the 2020 Final Action and publicly available information reported to the EPA and information contained in the EPA's National Electric Energy Data System (NEEDS) database.[10] Affected sources are required to use the 40 CFR part 75-based ECMPS [11] for reporting emissions and related data either directly for EGUs that use Hg, HCl, HF, or SO_2 CEMS or Hg sorbent traps for compliance purposes or indirectly as PDF files for EGUs that use performance test results, PM continuous parameter monitoring system (CPMS) data, or PM CEMS for compliance purposes. Directly submitted data are maintained in ECMPS; indirectly submitted data are maintained in Web Factor Information Retrieval System (WebFIRE).[12] The NEEDS database contains generation unit information used in the EPA's power sector modeling. Other sources used include the U.S. Department of Energy's EIA list of fuel consumption reported for 2021 under Form EIA–923 [13] and emissions test data collected from an ICR in 2010 (2010 ICR) when promulgating the 2011 Proposal.[14]

In conducting the technology review, the EPA examined information submitted to the EPA's ECMPS as well as information that supports previous 40 CFR part 63, subpart UUUUU actions to identify technologies currently being used by affected EGUs and to determine if there have been developments in practices, processes, or control technologies. In addition to the ECMPS data, we reviewed regulatory actions for similar combustion sources and conducted a review of literature published by industry organizations, technical journals, and government organizations.

E. How does the EPA perform the technology review?

Our technology review primarily focuses on the identification and evaluation of developments in practices, processes, and control technologies that have occurred since the MACT standards were promulgated. Where we identify such developments, we analyze

[10] See *https://www.epa.gov/airmarkets/power-sector-modeling-platform-v515.*

[11] See *https://ampd.epa.gov/ampd/.*

[12] See *https://cfpub.epa.gov/webfire; https://www.epa.gov/electronic-reporting-air-emissions/webfire.*

[13] See *https://www.eia.gov/electricity/data/eia923/.*

[14] See *https://www3.epa.gov/airtoxics/utility/utilitypg.html.*

the technical feasibility, estimated costs, energy implications, non-air environmental impacts, and potential emissions reductions of more stringent standards, to ensure that the MACT standards continue to fulfill Congress's direction to require the maximum degree of reduction of HAP taking into account the statutory factors. This analysis informs our decision of whether it is ''necessary'' to revise the emissions standards. In addition, we typically consider the appropriateness of applying controls to new sources versus retrofitting existing sources. For this exercise, we consider any of the following to be a ''development'':

• Any add-on control technology or other equipment that was not identified and considered during development of the original MACT standards;

• Any improvements in add-on control technology or other equipment (that were identified and considered during development of the original MACT standards) that could result in additional emission reductions; [15]

• Any work practice or operational procedure that was not identified or considered during development of the original MACT standards;

• Any process change or pollution prevention alternative that could be broadly applied to the industry and that was not identified or considered during development of the original MACT standards; and

• Any significant changes in the cost (including cost effectiveness) of applying controls (including controls the EPA considered during the development of the original MACT standards).

• Any operational changes or other factors that were not considered during the development of the original MACT standards.

In addition to reviewing the practices, processes, and control technologies that were considered at the time we originally developed (or last updated) the NESHAP, we review a variety of data sources in our investigation of potential practices, processes, or controls to consider. We also review the NESHAP and the available data to determine if there are any unregulated emissions of HAP within the source category and evaluate this data for use in developing new emission standards. When reviewing MACT standards, the EPA is required to address regulatory gaps, such as missing standards for listed air toxics known to be emitted from the source category, and any new MACT standards must be established under CAA sections 112(d)(2) and (3), or, in specific circumstances, CAA sections 112(d)(4) or (h). *Louisiana Environmental Action Network (LEAN)* v. *EPA,* 955 F.3d 1088 (D.C. Cir. 2020). See sections III.C and III.D of this preamble for information on the specific data sources that were reviewed as part of the technology review.

IV. Review of 2020 Residual Risk and Technology Review

A. Summary of the 2020 Residual Risk Review

Pursuant to CAA section 112(f)(2), the EPA conducted a residual risk review (2020 Residual Risk Review) and presented the results of this review, along with our decisions regarding risk acceptability, ample margin of safety, and adverse environmental effects, in the 2020 Final Action. The results of the risk assessment are presented briefly in Table 2, and in more detail in the document titled *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule* (risk document for the final rule), available in the docket (Docket ID No. EPA–HQ–OAR–2018–0794–4553).

TABLE 2—COAL- AND OIL-FIRED EGU INHALATION RISK ASSESSMENT RESULTS IN THE 2020 FINAL ACTION
[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 non-cancer HQ [4]
	Based on . . .		Based on . . .		Based on . . .		Based on . . .		
	Actual emissions level	Allowable emissions level	Actual emissions level	Allowable emissions level	Actual emissions level	Allowable emissions level	Actual emissions level	Allowable emissions level	Based on actual emissions level
332	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 located 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, we also show the HQ using the next lowest available acute dose-response value.

1. Chronic Inhalation Risk Assessment Results

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. The total estimated cancer incidence from this source category was 0.04 excess cancer cases per year, or one excess case in every 25 years. Approximately 193,000 people were estimated to have cancer risks at or above 1-in-1 million from HAP emitted from the facilities in this source category.[16] The estimated maximum chronic noncancer TOSHI for the source category was 0.2 (respiratory), which was driven by emissions of nickel and cobalt from oil-fired EGUs. No one was exposed to TOSHI levels above 1 based on actual emissions from sources regulated under this source category.

The EPA also evaluated the cancer risk at the maximum emissions allowed by the MACT standard (*i.e.,* ''allowable emissions''). As shown in Table 2 of this preamble, based on allowable emissions, the estimated cancer MIR

[15] This may include getting new or better information about the performance of an add-on or existing control technology (*e.g.,* emissions data from affected sources showing an add-on control technology performs better than anticipated during development of the rule).

[16] There were four facilities in the source category with cancer risk at or above 1-in-1 million, and all of them were facilities with oil-fired EGUs located in Puerto Rico.

was 10-in-1 million, and, as before, nickel emissions from oil-fired EGUs were the major contributor to the risk. The total estimated cancer incidence from this source category, considering allowable emissions, was 0.1 excess cancer cases per year, or one excess case in every 10 years. Based on allowable emissions, approximately 636,000 people were estimated to have cancer risks at or above 1-in-1 million from HAP emitted from the facilities in this source category. The estimated maximum chronic noncancer TOSHI for the source category was 0.4 (respiratory) based on allowable emissions, driven by emissions of nickel and cobalt from oil-fired EGUs. No one was exposed to TOSHI levels above 1 based on allowable emissions.

2. Screening Level Acute Risk Assessment Results

Because of the conservative nature of the acute inhalation screening assessment and the variable nature of emissions and potential exposures, acute impacts are screened on an individual pollutant basis, not using the TOSHI approach. Table 2 of this preamble provides the worst-case acute HQ (based on the REL) of 0.09, driven by emissions of arsenic. There were no facilities that have acute HQs (based on the REL or any other reference values) greater than 1. For more detailed acute risk results, refer to the risk document available in the docket (Docket ID No. EPA–HQ–OAR–2018–0794–4553).

3. Multipathway Risk Screening and Site-Specific Assessment Results

Potential multipathway health risks under a fisher and gardener scenario were evaluated using a three-tier screening assessment of the HAP known to be persistent and bio-accumulative in the environment (PB–HAP) emitted by facilities in the coal- and oil-fired EGU source category. This evaluation resulted in a site-specific assessment of Hg using the EPA's Total Risk Integrated Methodology.Fate, Transport, and Ecological Exposure (TRIM.FaTE) model for one location (three facilities located in North Dakota) as further described below. Of the 322 MATS-affected facilities modeled, 307 facilities had reported emissions of carcinogenic PB–HAP (arsenic, dioxins, and polycyclic organic matter (POM)) that exceeded a Tier 1 cancer screening value of 1, which corresponds to an upper bound maximum excess lifetime cancer risk that may be greater than 1-in-1 million. This source category also had 235 facilities reporting emissions of non-carcinogenic PB–HAP (lead, Hg, and cadmium) that exceeded an upper bound Tier 1 noncancer screening value of 1, which corresponds to a HQ of 1 For facilities that exceeded a Tier 1 multipathway screening value of 1, we used additional facility site-specific information to perform a refined screening assessment through Tiers 2 and 3, as necessary, to determine the maximum chronic cancer and noncancer impacts for the source category. For cancer, the highest Tier 2 screening value for the gardener scenario (rural) was 200 driven by arsenic emissions. This screening value was reduced to 50 after accounting for plume rise in our Tier 3 screen. Because this screening value was much lower than 100-in-1 million, and because we expected the actual risk from a site-specific assessment to further lower the Tier 2 screening value by a factor of 50, we decided not to perform a site-specific assessment for cancer. For noncancer, the highest Tier 2 screening value was 30 (for Hg) for the fisher scenario, with four facilities having screening values greater than 20. These screening values were reduced to 9 or lower after the plume rise stage of Tier 3.

Because the final stage of Tier 3 (time-series) was unlikely to reduce the highest Hg screening values to 1, we conducted a site-specific multipathway assessment of Hg emissions for this source category. Analysis of the facilities with the highest Tier 2 and Tier 3 screening values helped identify the location for the site-specific assessment and the facilities to model with TRIM.FaTE. The assessment considered the effect that multiple facilities within the source category may have on common lakes. The three facilities selected were located near Underwood, North Dakota. All three facilities had Tier 2 screening values greater than or equal to 20. Two of the facilities were near each other (16 kilometers (km) apart). The third facility was more distant, about 20 to 30 km from the other facilities, but it was included in the analysis because it is within the 50-km modeling domain of the other facilities and because it had an elevated Tier 2 screening value. We expected that the exposure scenarios we assessed for these facilities are among the highest, if not the highest, that might be encountered for other facilities in this source category based upon their Hg emissions and their respective Tier 2 screening values and aggregate impacts to common lakes. The refined site-specific multipathway assessment estimated an HQ of 0.06 for Hg for the three facilities assessed. We believed the assessment represented the highest potential for Hg hazards through fish consumption for the source category based upon an upper-end fish ingestion rate of 373 grams/day.

In evaluating the potential multipathway risk from emissions of lead compounds, rather than developing a screening threshold emission rate, we compared maximum estimated chronic inhalation exposure concentrations to the level of the current National Ambient Air Quality Standards (NAAQS) for lead (0.15 micrograms per cubic meter). Values below the level of the primary (health-based) lead NAAQS were considered to have a low potential for multipathway risk. We did not estimate any exceedances of the lead NAAQS in this source category, the maximum predicted Pb screen concentration over a 3-month period for this source category was equal to 0.005 micrograms per cubic meter, significantly below the Pb NAAQS.

4. Environmental Risk Screening Results

An environmental risk screening assessment for the coal- and oil-fired EGU source category was conducted for the following pollutants: arsenic, cadmium, dioxins/furans, HCl, HF, lead, Hg (methylmercury and mercuric chloride), and POMs. In the Tier 1 screening analysis for PB–HAP (other than lead, which was evaluated differently), POM emissions had no exceedances of any of the ecological benchmarks evaluated. Arsenic and dioxin/furan emissions had Tier 1 exceedances for surface soil benchmarks. Cadmium and methylmercury emissions had Tier 1 exceedances for surface soil and fish benchmarks. Divalent Hg emissions had Tier 1 exceedances for sediment and surface soil benchmarks.

A Tier 2 screening analysis was performed for arsenic, cadmium, dioxins/furans, divalent Hg, and methylmercury emissions. In the Tier 2 screening analysis, arsenic, cadmium, and dioxin/furan emissions had no exceedances of any of the ecological benchmarks evaluated. Divalent Hg emissions from two facilities exceeded the Tier 2 screen for a sediment threshold level benchmark by a maximum screening value of 2. Methylmercury emissions from the same two facilities exceeded the Tier 2 screen for a fish (avian/piscivores) no-observed-adverse-effect-level (NOAEL) (merganser) benchmark by a maximum screening value of 2. A Tier 3 screening assessment was performed to verify the existence of the lake associated with these screening values, and it was found to be located on-site and is a man-made industrial pond, and, therefore, was removed from the assessment.

Methylmercury emissions from two facilities exceeded the Tier 2 screen for a surface soil NOAEL for avian ground insectivores (woodcock) benchmark by a maximum screening value of 2. Other surface soil benchmarks for methylmercury, such as the NOAEL for mammalian insectivores and the threshold level for the invertebrate community, were not exceeded. Given the low Tier 2 maximum screening value of 2 for methylmercury, and the fact that only the most protective benchmark was exceeded, a Tier 3 environmental risk screen was not conducted for methylmercury.

For lead, we did not estimate any exceedances of the secondary lead NAAQS. For HCl and HF, the average modeled concentration around each facility (*i.e.,* the average concentration of all off-site data points in the modeling domain) did not exceed any ecological benchmark. In addition, each individual modeled concentration of HCl and HF (*i.e.,* each off-site data point in the modeling domain) was below the ecological benchmarks for all facilities.

Based on the results of the environmental risk screening analysis, we did not expect an adverse environmental effect as a result of HAP emissions from the coal- and oil-fired EGU source category.

5. Facility-Wide Risk Results

An assessment of risk from facility-wide emissions was performed to provide context for the source category risks. Based on facility-wide emissions estimates developed using the same estimates of actual emissions for emissions sources in the source category, and emissions data from the 2014 National Emissions Inventory (NEI) (version 2) for the sources outside the source category, the estimated cancer MIR was 9-in-1 million, and nickel emissions from oil-fired EGUs were the major contributor to the risk. The total estimated cancer incidence based on facility-wide emissions was 0.04 excess cancer cases per year, or one excess case in every 25 years. Approximately 203,000 people were estimated to have cancer risks at or above 1-in-1 million from HAP emitted from all sources at the facilities in this source category. The estimated maximum chronic noncancer TOSHI posed by facility-wide emissions was 0.2 (respiratory), driven by emissions of nickel and cobalt from oil-fired EGUs. No one was exposed to TOSHI levels above 1 based on facility-wide emissions. These results were very similar to those based on actual emissions from the source category because there was not significant collocation of other sources with EGUs.

6. Decisions Regarding Risk Acceptability, Ample Margin of Safety, and Adverse Environmental Effect

In determining whether residual risks are acceptable for this source category in accordance with CAA section 112, the EPA considered all available health information and risk estimation uncertainty. The results of the risk analysis indicated that both the actual and allowable inhalation cancer risks to the individual most exposed were below 100-in-1 million, which is the presumptive limit of acceptability. Also, the highest chronic noncancer TOSHI and the highest acute noncancer HQ were below 1, indicating low likelihood of adverse noncancer effects from inhalation exposures. There were also low risks associated with ingestion, with the highest cancer risk being less than 50-in-1 million based on a conservative screening assessment, and the highest noncancer hazard being less than 1 based on a site-specific multipathway assessment. Considering this information, the EPA determined in 2020 that the residual risks of HAP emissions from the coal- and oil-fired EGU source category were acceptable.

We then considered whether the current standards provided an ample margin of safety to protect public health and whether more stringent standards were necessary to prevent an adverse environmental effect by taking into consideration costs, energy, safety, and other relevant factors. In determining whether the standards provided an ample margin of safety to protect public health, we examined the same risk factors that we investigated for our acceptability determination and we also considered the costs, technological feasibility, and other relevant factors related to emissions control options that might reduce risk associated with emissions from the source category. In our analysis, we considered the results of the technology review, risk assessment, and other aspects of our MACT rule review to determine whether there were any cost-effective controls or other measures that would reduce emissions further to provide an ample margin of safety. The risk analysis indicated that the risks from the source category are low for both cancer and noncancer health effects. Thus, we determined in 2020 that the current MATS requirements provided an ample margin of safety to protect public health in accordance with CAA section 112.

Based on the results of our environmental risk screening assessment, we also determined in 2020 that more stringent standards were not necessary to prevent an adverse environmental effect.

B. Summary of the 2020 Technology Review

Pursuant to CAA section 112(d)(6), the EPA conducted a technology review (2020 Technology Review) in the 2020 Final Action, which focused on identifying and evaluating developments in practices, processes, and control technologies for the emission sources in the source category that occurred since the MATS rule was promulgated. Control technologies typically used to minimize emissions of pollutants that have numeric emission limits under the MATS rule include electrostatic precipitators (ESPs) and fabric filters (FFs) for control of non-Hg HAP metals; wet scrubbers and dry scrubbers for control of acid gases (SO_2, HCl, and HF); and activated carbon injection (ACI) for control of Hg. The EPA determined that existing air pollution control technologies that were in use were well-established and provided the capture efficiencies necessary for compliance with the MATS emission limits. Based on the effectiveness and proven reliability of these control technologies, and the relatively short period of time since the promulgation of the MATS rule, the EPA did not identify any developments in practices, processes, or control technologies, nor any new technologies or practices, for the control of non-Hg HAP metals, acid gas HAP, or Hg. However, in the 2020 Technology Review, the EPA did not consider developments in the cost and effectiveness of these proven technologies, nor did the EPA evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs, to determine whether revising the standards was warranted. Organic HAP, including emissions of dioxins and furans, are regulated by a work practice standard that requires periodic burner tune-ups to ensure good combustion. The EPA found that this work practice continued to be a practical approach to ensuring that combustion equipment was maintained and optimized to run to reduce emissions of organic HAP and continued to be more effective than establishing a numeric standard that cannot reliably be measured or monitored. Based on the effectiveness and proven reliability of the work practice standard, and the relatively short amount of time since the promulgation of the MATS rule, the EPA did not identify any developments in work practices nor any new work practices or operational procedures for this source category regarding the additional control of organic HAP.

After conducting the 2020 Technology Review, the EPA did not identify developments in practices, processes, or control technologies and, thus, did not propose changes to emission standards or other requirements. More information concerning that technology review is in the memorandum titled *Technology Review for the Coal- and Oil-Fired EGU Source Category,* available in the docket (Docket ID No. EPA–HQ–OAR–2018–0794–0015), and in the February 7, 2019, proposed rule. 84 FR 2700. On May 20, 2020, the EPA finalized the first technology review required by CAA section 112(d)(6) for the coal- and oil-fired EGU source category regulated under MATS. Based on the results of that technology review, the EPA found that no revisions to MATS were warranted. See 85 FR 31314 (May 22, 2020).

V. Analytical Results and Proposed Decisions

As described in section IV, the EPA conducted a residual risk review under CAA section 112(f) and presented results of the review in the 2020 Final Action. Executive Order 13990, ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis'' required the EPA to review the 2020 Final Action and consider publishing a notice of proposed rulemaking suspending, revising, or rescinding the 2020 Final Action. As part of this effort, the EPA solicited information to inform a review of the MATS RTR in the 2022 Proposal affirming it is appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112. The EPA summarizes the results of the review of the RTR and proposed decisions consequent of the review below and requests comment on specific considerations. In addition to generally soliciting comments on all aspects of this proposed action, the EPA is requesting public comment on specific issues as described below. In addition, the EPA is granting in part certain petitions for reconsideration on the Agency's prior rulemakings, which are discussed in further detail below.

A. Review of the 2020 Residual Risk Review

The EPA has reviewed the 2020 Residual Risk Review as directed by E.O. 13990. This included a review of the 2020 residual risk assessment described in Docket ID No. EPA–HQ–OAR–2018–0794–0014 and consideration of comments received in response to the 2022 Proposal. The EPA did not receive any new information in response to the 2022 Proposal that would affect the EPA's 2020 residual risk analysis or the decisions emanating from that analysis. In reviewing the 2020 residual risk analysis, the EPA has determined that the risk analysis was a rigorous and robust analytical review using approaches and methodologies that are consistent with those that have been utilized in residual risk analyses and reviews for other industrial sectors. In addition, the results of the 2020 residual risk assessment, as summarized in section IV.A of this preamble, indicated low residual risk from the coal- and oil-fired EGU source category. For these reasons, we are not proposing any revisions to the 2020 Residual Risk Review. Although we are not reopening the 2020 determination of whether residual risks would alone be sufficient under the CAA to necessitate new standards, the EPA acknowledges that the revised standards being proposed under this technology review, as explored below, will likely reduce HAP exposures to affected populations. In recognition of the hazardous nature of these HAP, Congress intentionally created a two-pronged structure for updating standards for toxic air pollutants that requires the EPA to continue assessing opportunities to strengthen the standards under CAA section 112(d)(6) even after residual risks have been addressed under CAA section 112(f)(2).[17] Under this structure, recognizing the value of reducing any exposure to HAP where feasible, the EPA is obligated to update standards where *either* the EPA finds it is necessary to provide an ample margin of safety to protect public health or where the EPA finds it is necessary taking into account developments in practices, processes, and control technologies. The EPA also acknowledges that it received a petition for reconsideration from environmental organizations that, in relevant part, sought the EPA's reconsideration of certain aspects of the 2020 Residual Risk Review, which the EPA continues to review and will respond to in a separate action.[18]

B. Review of the 2020 Technology Review

The EPA's review of the 2020 Technology Review included evaluating the technology review described in Docket ID No. EPA–HQ–OAR–2018–0794–0015 and comments related to potential practices, processes, or controls received as part of the 2022 Proposal. The review also focused on the identification and evaluation of any developments in practices, processes, and control technologies that have occurred since finalization of the MATS rule in 2012 and since publishing the 2020 Technology Review. As explained in detail herein, based on this information, the EPA now concludes that developments in the costs and effectiveness of control technologies and the related fact that emissions performance still varies significantly, warrant revising certain MACT standards.

Technology reviews can, and often do, include obtaining better information about the performance of a control technology (*e.g.,* emissions data from affected sources) showing that an add-on technology that was identified and considered during the development of the original MACT standards works better (*e.g.,* gets more emissions reductions or costs less) than anticipated. In fact, considering data on outperforming sources and cost and effectiveness of existing controls is well established. See, *e.g.,* Coke Oven Batteries, 69 FR 48338, 48351 (August 9, 2014) (''[A]lthough no new control technologies have been developed since the original standards were promulgated, our review of emissions data revealed that existing MACT track batteries can achieve a level of control for door leaks and topside leaks more stringent than that required by the 1993 national emission standards . . . through diligent work practices to identify and stop leaks.''); Site Remediation, 85 FR 41680, 41690 (July 10, 2020) (noting that commenters had not identified developments like a reduction in costs); Petroleum

[17] The EPA has long considered these two inquiries independent. See, *e.g.,* Mineral Wool Production and Wool Fiberglass Manufacturing, 80 FR 45280, 45292 (July 29, 2015) (explaining CAA section 112(d)(6) and 112(f)(2) ''standards rest on independent statutory authorities and independent rationales.''); *see also Ass'n of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667, 672 (D.C. Cir. 2013) (CAA section 112(d)(6) ''directs EPA to take into account developments in practices, processes, and control technologies, . . . not risk reduction achieved by the additional controls.'') (internal quotation omitted). Indeed, the EPA has strengthened standards based upon its technology review while finding residual risks acceptable numerous times. See, *e.g.,* Site Remediation, 85 FR 41680 (July 10, 2020); Organic Liquids Distribution, 85 FR 40740 (July 7, 2020); Ethylene Production, 85 FR 40386 (July 6, 2020); Pulp Mills, 82 FR 47328 (Oct. 11, 2017); Acrylic and Modacrylic Fibers Production, 79 FR 60898 (Oct. 8, 2014); Natural Gas Processing Plants, 77 FR 49400 (Aug. 16, 2012); Wood Furniture Manufacturing Operations, 76 FR 72052 (Nov. 21, 2011).

[18] See Docket ID No. EPA–HQ–OAR–2018–0794–4565 at *www.regulations.gov.*

Refineries, 80 FR 75178, 75201 (December 1, 2015); Mineral Wood Production and Fiberglass Manufacturing, 80 FR 45280, 45284–85 (July 29, 2015); *see also Nat'l Ass'n for Surface Finishing* v. *EPA,* 795 F3d 1, 11–12 (D.C. Cir 2015).

For example, in the 2014 technology review for Ferroalloys Production, the EPA found that PM emission levels were well below the MACT standards established in the original 1999 NESHAP. These findings ''demonstrate[d] that the add-on emission control technology (venturi scrubber, positive pressure FF, negative pressure FF) used to control emissions from the furnaces are quite effective in reducing PM (used as a surrogate for metal HAP) and that all of the facilities have emissions well below the current limits.'' See 79 FR 60271 (October 6, 2014). Therefore, the EPA determined that it was appropriate to revise the PM limits for furnaces. Similarly, in the 2017 technology review for Wool Fiberglass Manufacturing, the EPA found that formaldehyde emissions had decreased by approximately 95 percent since promulgation of the MACT Standards in the original 1999 NESHAP due to ''(1) Improvements in control technology (*e.g.,* improved bag materials, replacement of older baghouses) and (2) the use of electrostatic precipitators,'' as well as upgraded pollution prevention practices (*i.e.,* development and use non-phenol-formaldehyde binders). See 82 FR 40975 (August 29, 2017). Although the EPA declined to lower the formaldehyde limit in this case, it was only because the source category had already upgraded the technology (*i.e.,* non-phenol-formaldehyde binders), resulting in major sources becoming area sources that were no longer subject to the NESHAP.

As in those cases, here many commenters provided data showing that control technologies are more widely used, more effective, and cheaper than at the time EPA promulgated MATS. For example, commenters explained that, due to the many options that are available to control Hg emissions (*e.g.,* control equipment, activated carbon, reagents and sorbents, as well as fuel blending, non-carbon or improvements to carbon-based solvents, wet and dry scrubber additives, oxidizing coal additives, and existing control optimization) and a ''robust industry of technology suppliers that drive innovation through internal research and development,'' the costs of compliance for end users has decreased over time (Docket ID No. EPA–HQ–OAR–2018–0794–4940). Similarly, commenters noted that the large number of EGUs that are outperforming the current Hg and fPM standards would support a decision to revise the standards (Docket ID No. EPA–HQ–OAR–2018–0794–4962). Specific comments leading to our proposed decisions are detailed below, and a summary of this technology review is provided in the memorandum ''2023 Technology Review for the Coal- and Oil-Fired EGU Source Category,'' which can be found in Docket ID No. EPA–HQ–OAR–2018–0794. Based on our review of the 2020 Technology Review, the EPA is proposing to revise the current standards as discussed below.

C. What are the results and proposed decisions based on our technology review, and what is the rationale for those decisions?

This section summarizes the EPA's changes to the 2020 technology review and proposed decisions. Where the EPA has identified developments in practices, processes, or controls, we analyzed the technical feasibility, estimated costs, energy implications, and non-air environmental impacts, as well as the potential emission reductions associated with each development. In addition, we reviewed a variety of data sources in our investigation of developments in practices, processes, or controls. See section III of this preamble for information on the specific data sources that were reviewed as part of the technology review.

1. Filterable Particulate Matter (fPM) Emission Limit (as a Surrogate for Non-Hg HAP Metals)

As described in section III of this preamble, EGUs in six subcategories are subject to numeric emission limits for each of the individual non-Hg metal HAP. Alternatively, certain affected EGUs can choose to demonstrate compliance with an alternative total non-Hg metal HAP emission limit. Finally, affected EGUs can demonstrate compliance with an alternative fPM emission limit that serves as a surrogate for total non-Hg metal HAP. The EPA chose fPM as a surrogate for non-Hg metal HAP in the original MATS rulemaking because non-Hg metal HAP are predominantly a component of the filterable fraction of total PM (which is comprised of a filterable fraction and a condensable fraction), and control of fPM results in co-reduction of non-Hg metal HAP (with the exception of Se, which may be present in the filterable fraction or in the condensable fraction as the acid gas, SeO_2). Additionally, not all fuels emit the same type and amount of non-Hg metal HAP, but most generally emit fPM that includes some amount and combination of all the non-Hg metal HAP. Lastly, the use of fPM as a surrogate eliminates the cost of performance testing to demonstrate compliance with numerous standards for individual non-Hg metal HAP (Docket ID No. EPA–HQ–OAR–2009–0234). For these reasons, the EPA focused its review on the fPM emissions of coal-fired EGUs as a surrogate for non-Hg metal HAP.

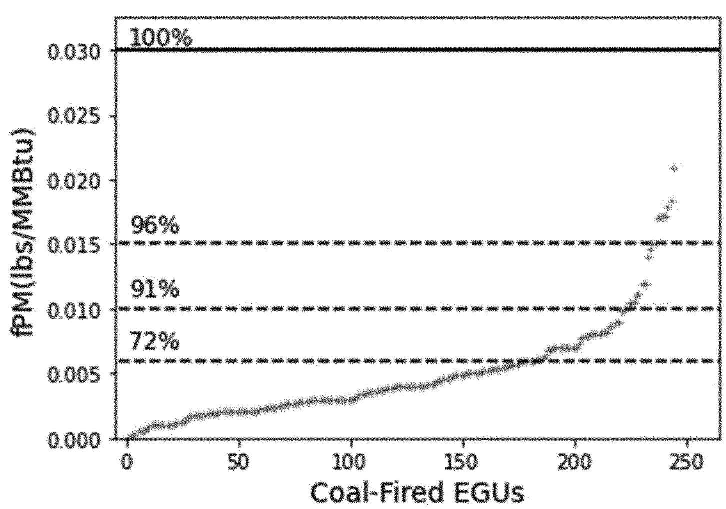
In the 2020 Technology Review, the EPA did not identify any developments in practices, processes, or control technologies for non-Hg metal HAP or fPM. The assessment of implementation and developments in non-Hg metal HAP metal is summarized in the memorandum, ''Technology Review for the Coal- and Oil-Fired EGU Source Category,'' which is included in Docket ID No. EPA–HQ–OAR–2018–0794–0015. The 2020 review simply presented a list of PM control technologies used by coal-fired EGUs in operation, finding that the units primarily employ ESPs and FFs, and did not identify any new control technologies to reduce non-Hg metal HAP. That review did not consider or discuss the costs or performance of already-installed controls nor discuss or analyze opportunities for improved performance. In the 2020 Technology Review, the EPA concluded that ''[t]he PM air pollution control device technologies that are currently in use are well-established and provide the capture efficiencies necessary for compliance with the subpart UUUUU [MATS] filterable PM limits.'' In the 2022 Proposal, the EPA solicited information on the cost and performance of new or improved control technologies that control HAP emissions and improved methods of operation.

In this review of the RTR, and consistent with some past technology reviews, the EPA assessed the performance of the sources in the source category compared to current standards, and the EPA accordingly expanded upon the 2020 Final Action's technology review to assess the fPM emission performance of the fleet. This review included evaluating the control efficiency and costs of common control systems used for fPM control, primarily ESPs and FFs, detailed in the memorandum (Technical Memo), ''2023 Technology Review for the Coal- and Oil-Fired EGU Source Category,'' which is included in Docket ID No. EPA–HQ–OAR–2018–0794. As part of this effort, the EPA reviewed more recent fPM compliance data that was not available during the 2020 Final Action. Although our review of fPM compliance data for coal-fired EGUs indicated no new practices, processes, or control technologies for non-Hg metal HAP, it revealed two important developments that inform the EPA's decision to propose revisions to the standard. First, it revealed that most existing coal-fired EGUs are reporting fPM well below the current fPM emission limit of 3.0E–02 lb/MMBtu. Information we received in response to the 2022 Proposal similarly noted that the fleet is reporting much lower fPM rates than what is currently allowed. Second, it revealed that the fleet is achieving these performance levels at lower costs than assumed during promulgation of the original MATS fPM emission limit. More specifically, one commenter presented its fleetwide evaluation using data from 100 coal units in the PJM Interconnection and in the Electric Reliability Council of Texas (ERCOT) markets. The commenter's analysis suggested that only 42 EGUs would require additional capital or operating costs to meet a more stringent fPM limit of 7.0E–03 lb/MMBtu, while 79 EGUs would incur those costs to meet a limit of 3.75E–03 lb/MMBtu. The commenter's analysis suggested that most units would incur costs in the range of $0/kW to $75/kW (Docket ID No. EPA–HQ–OAR–2018–0794–5121). Other commenters pointed to an independent report finding that units are doing ''just enough'' to satisfy the MATS limits and that EGUs can achieve fPM emission rates at or below 7.0E–03 lb/MMBtu with relatively low capital cost upgrades to pollution control systems.[19] Commenters also cited studies finding the actual costs of complying with air pollution regulations are often substantially lower than pre-compliance estimates assumed in the 2012 MATS Final Rule.

Figure 1 shows that all coal-fired EGUs are reporting fPM emissions well below the current MATS limit of 3.0E–02 lb/MMBtu, and that 91 percent of EGUs are reporting fPM emissions at levels lower than a third of the current limit. In fact, the average reported fPM rate of the EGUs assessed in Figure 1 is 4.8E–03 lb/MMBtu, which is 84 percent below the MATS current limit (the median is 4.0E–03 lb/MMBtu, or 87 percent below the MATS current limit). The EPA evaluated the fPM emission performance of EGUs and binned them by quartiles. The average fPM emission rate reported by the best performing 25 percent was 1.4E–03 lb/MMBtu. Of the best performing 50 percent of EGUs assessed, the average fPM emission rate was 2.4E–03 lb/MMBtu and the average fPM rate reported by the best 75 percent was 3.1E–03 lb/MMBtu. Of the best performing 95 percent, the average fPM emission rate was 4.2E–03 lb/MMBtu. Even the higher emitting units, with reported rates above the current fPM LEE standard, are performing 30 percent to 43 percent below the current standard. Even so, the handful of the worst performing EGUs are reporting fPM at rates approximately three to four times the fleet average.

Because an evaluation of compliance data showed that a significant portion of coal-fired EGUs are performing well below the allowed emission limit (Figure 1), and because the EPA obtained information indicating lower costs to improve controls to achieve additional fPM emission reductions than assumed during promulgation of the original MATS fPM emission limit, the EPA concluded that there were developments that warranted an examination of whether to revise the standard.

To examine potential revisions, the EPA used representative fPM emissions as a surrogate for total non-Hg metal HAP to evaluate three more stringent emission limits. The fPM emission limits that were evaluated are (1) 1.5E–02 lb/MMBtu, which is 50 percent of the current limit and the qualifying emission rate for the LEE program (2) 1.0E–02 lb/MMBtu, which is comparable to the MATS new source fPM emission limit; and (3) 6.0E–03 lb/MMBtu, which is the average fPM emission rate from the 2010 ICR. Currently, 96 percent of existing coal-fired capacity without known retirement plans before the proposed compliance period[20] already have demonstrated an emission rate of 1.5E–02 lb/MMBtu or lower, 91 percent of existing coal-fired capacity have demonstrated an emission rate of 1.0E–02 lb/MMBtu or lower, and 72 percent of existing coal-fired capacity have demonstrated an emission rate of 6.0E–03 lb/MMBtu or lower. As mentioned above, the average fPM rate of the best performing 95 percent of EGUs was 4.2E–03 lb/MMBtu, below the most stringent option analyzed of 6.0E–03 lb/MMBtu. The EPA evaluated reductions of the 10 individual non-Hg metal HAP, total non-Hg metal HAP, and fPM and the associated costs for each unit to achieve each of the three fPM emission limits listed above.



[19] See *https://www.andovertechnology.com/wp-content/uploads/2021/08/PM-and-Hg-Controls_CAELP_20210819.pdf.*

[20] If the proposed revised emission limits are finalized, affected EGUs will have up to 3 years after the effective date of the rule amendments to demonstrate compliance with the revised emission limits.

Figure 1—fPM rate distribution for affected coal-fired EGUs in the continental U.S. in reference to the three considered fPM limit (horizontal dashed lines): 1.5E–02 lb/MMBtu, 1.0E–02 lb/MMBtu, and 6.0E–03 lb/MMBtu. Percentages represent the amount of existing capacity achieving each of the limits. More information available in the Technical Memo supporting this action.

The EPA discussed the opportunity for improved performance of existing fPM control technologies in the 2012 MATS Final Rule. In the regulatory impact analysis (RIA) supporting the 2012 MATS Final Rule, the EPA estimated that 34 gigawatts (GW) of coal-fired EGU capacity would perform ESP upgrades as part of their fPM emission limit compliance strategy.[21] EPA's methodology was based on historic PM emission rates and reported control efficiencies and is explained in the IPM 4.10 Supplemental Documentation for MATS.[22] Depending on the incremental fPM reduction needed to bring a unit into compliance, units with existing ESPs for PM control were assigned either a FF retrofit or one of three tiered ESP upgrades to bring them into compliance. In response to the solicitation in the 2022 Proposal, commenters provided detailed information on updated costs for similar upgrades for improved ESP performance. Using that data and additional information from one of the EPA's engineering consultants, the EPA evaluated revised costs to upgrade existing PM controls. The cost effectiveness estimates presented in this section are based on an assumption that eight units would need to upgrade existing ESPs to comply with a revised fPM emission standard of 1.5E–02 lb/MMBtu, that 20 units would need to implement similar ESP upgrades to comply with a revised fPM emission standard of 1.0E–02 lb/MMBtu, and that 65 units would need to install a new FF or modify an existing FF to meet a revised fPM emission limit of 6.0E–03 lb/MMBtu.

In this proposal, the EPA proposes to set an fPM emission limit of 1.0E–02 lb/MMBtu (0.010 lb/MMBtu) and seeks comment on whether its control technology effectiveness and cost assumptions are correct, and whether it should finalize a more stringent standard. The EPA's decision to propose a standard of 1.0E–02 lb/MMBtu is based on several factors. First, this level of control would ensure that the very worst performers bring their performance level up to where the vast majority of the fleet is performing. The EPA notes that Figure 1 shows a ''knee in the curve'' that starts before 1.0E–02 lb/MMBtu, with coal-fired EGUs above that rate emitting substantially more pollution than those below it. Bringing this small number of sources (9 percent of coal-fired EGU capacity) to the performance of the rest of the fleet serves Congress's mandate to the EPA to continually consider developments and to ensure that standards account for developments ''that create opportunities to do even better.'' *See LEAN,* 955 F.3d at 1093. As discussed above in section V.B. of this document, the EPA has a number of times in the past updated its MACT standards to reflect developments where the majority of sources is vastly outperforming the original MACT standards.

According to comments received in response to the solicitation in the 2022 Proposal, since the MATS Final Rule was promulgated in 2012, improvements to existing PM controls to comply with the MATS fPM standard were achieved at lower costs than had been projected by the EPA. The commenter also noted that industry installed far fewer FFs than the EPA projected and that there were a smaller number of ESP upgrades than projected. The 2012 MATS Final Rule used the Upper Predictive Limit (UPL) to establish the fPM emission limit of 3.0E–02 lb/MMBtu for existing coal-fired EGUs. The UPL considers the average of the best performing EGUs, but also includes an allowance for variation that is determined by a confidence level that the UPL will not be exceeded. A report[23] submitted to the EPA in response to the 2020 Proposal presented an updated UPL (using 2019 data compiled by Natural Resources Defense Council (NRDC)[24]) of 5.0E–03 lb/MMBtu, about one-sixth of the EPA's 2011 estimate of 3.0E–02 lb/MMBtu. The updated 5.0E–03 lb/MMBtu UPL value was attributed to updated fPM rates that were lower on average and reflected less variability in emissions for each individual EGU. More specifically, according to the commenter, the lower fPM emissions and thus lower UPL were attributed to: (1) greater attention to fPM emissions due to the monitoring and reporting requirements of MATS; (2) efforts to restore ESPs and other equipment to original designed performance levels; (3) modest improvements to ESPs when needed, such as addition of high frequency transformer rectifier (TR) sets; and (4) efforts to minimize the wear and tear on filter bags and increased attention to FF operation. Developments in the technology, including better performance at lower costs, combined with improved variability assumptions updated since promulgation of the 2012 MATS Final Rule, presents an opportunity to strengthen the MACT standard for fPM.

Second, the EPA believes that a fPM emission limit of 1.0E–02 lb/MMBtu appropriately takes into account the costs of control. The EPA evaluated the costs to improve current PM control systems and the cost to install better performing PM controls (*i.e.,* a new FF) to achieve a more stringent emission limit. As noted above, data received since 2012 demonstrates that the costs of PM control upgrades are likely much lower than the EPA estimated in 2012. Table 3 summarizes the estimated cost-effectiveness of the three emission limits evaluated for the existing fleet. For the purpose of estimating cost-effectiveness, the analysis presented in this table is based on the observed emissions rates of all existing coal-fired EGUs except for those that have announced plans to retire by the end of 2028. Note that, unlike the cost and benefit projections presented in the RIA for this proposed rule, the estimates in this table do not account for any future changes in the composition of the operational coal-fired EGU fleet that are likely to occur by 2028 as a result of other factors affecting the power sector, such as the Inflation Reduction Act (IRA), future regulatory actions, or changes in economic conditions. Of the over 9 GW of coal-fired capacity that the EPA estimates would require control improvements to achieve the proposed fPM rate, less than 5 GW is projected to be operational in 2028 (see section 3 of the RIA for this proposal).

[21] Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, available *https://www.epa.gov/sites/default/files/2015-11/documents/matsriafinal.pdf* and in the rulemaking docket.

[22] See Table 5–25 in Documentation Supplement for EPA Base Case v.4.10_MATS—Updates for Final Mercury and Air Toxics Standards (MATS) Rule available at *https://www.epa.gov/sites/default/files/2015-07/documents/suppdoc410mats.pdf* and in the rulemaking docket.

[23] See *https://www.andovertechnology.com/wp-content/uploads/2021/08/PM-and-Hg-Controls_CAELP_20210819.pdf.*

[24] *https://www.nrdc.org/resources/coal-fired-power-plant-hazardous-air-pollution-emissions-and-pollution-control-data.*

TABLE 3—SUMMARY OF COST EFFECTIVENESS ANALYSIS FOR THREE POTENTIAL fPM EMISSION LIMITS [1]

	Potential fPM emission limit (lb/MMBtu)		
	1.5E–02	1.0E–02	6.0E–03
Affected Units (Capacity, GW)	8 (4.02)	20 (9.34)	65 (32.9)
Annual Cost ($M)	13.9–19.3	77.3–93.2	633
fPM Reductions (tons/year)	463	2,074	6,163
Total non-Hg metal HAP Reductions (tons/year)	1.41	6.34	24.7
Total non-Hg metal HAP Cost Effectiveness ($k/ton)	9,860–13,700	12,200–14,700	25,600
Total non-Hg metal HAP Cost Effectiveness—Allowable ($k/ton)	35.4–49.1	197–238	1,610

[1] Note that these values represent annual cost and projected emission reductions assuming the affected coal-fired EGUs operate consistent with their operation in their lowest quarter (see Technical Memo accompanying this action for more information).

The cost estimates presented in this table could be overestimated for a number of reasons, and the EPA seeks comment on these cost and cost-effectiveness estimates and how they may change over time. Additionally, the information in Table 3 shows that coal-fired EGUs have demonstrated an ability to meet these limits with existing control technology. It is possible that some EGUs with the same or similar technologies may be able to achieve a lower fPM rate at significantly lower cost than assumed here, and possibly without any additional capital investments. Furthermore, since the EGU-specific fPM emissions rate is calculated using the largest 1 percent of fPM rates for the quarter with the lowest emissions, some EGUs may readily achieve lower fPM rates with improved operation. While such factors could likely lower the overall cost estimates and improve cost-effectiveness, this table presents estimates based on the best information available to the EPA at this time.

The EPA considers costs in various ways, depending on the rule and affected sector. For example, the EPA has considered, in previous CAA section 112 rulemakings, cost-effectiveness, the total capital costs of proposed measures, annual costs, and costs compared to total revenues (*e.g.,* cost to revenue ratios).[25] Because much of the fleet is already reporting fPM rates below 6.0E–03 lb/MMBtu, both the total costs and the total fPM and non-Hg metal HAP reductions for the three potential emission limits are modest in the context of the total control costs and emissions of the coal fleet. The cost-effectiveness estimates for EGUs reporting fPM rates above 6.0E–03 lb/MMBtu to achieve similar performance as the rest of the fleet range from $9,860,000 to $25,600,000 per ton of non-Hg metal HAP for the three potential emission limits.

For this proposal, the costs—either the annual control cost estimates presented above in Table 3 or the projected total annual system-wide compliance costs presented in Table 3–4 in the RIA—represent a very small fraction of typical capital and total expenditures for the power sector. In the 2022 Proposal (reaffirming the appropriate and necessary finding), the EPA evaluated the compliance costs that were projected in the 2012 MATS rule relative to the typical annual revenues, capital expenditures, and total (capital and production) expenditures.[26] (January 11, 2022); 80 FR 37381 (June 30, 2015). Using electricity sales data from the U.S. EIA, the analysis in the 2022 Proposal demonstrated that revenues from retail electricity sales increased from $276.2 billion in 2000 to a peak of $356.6 billion in 2008 (an increase of about 29 percent during this period) and have slowly declined since to a post-2011 low of $331.0 billion in 2019 (a decrease of about 7 percent from its peak during this period) in 2007 dollars. The annual control cost estimates for this proposal based on the cost-effectiveness analysis in Table 3 constitute at most about 0.2 percent of sector sales at their lowest over the 2000 to 2019 period. Making similar comparisons of the estimated capital and total compliance costs to historical trends in sector-level capital and production costs, respectively, would yield similarly small values. Because this cost-effectiveness evaluation only considers improved fPM control needed at a few units and not the entire fleet, we also evaluated an alternative cost-effectiveness approach that considers allowable emissions, assuming emission reductions achieved if all evaluated EGUs emit the maximum allowable amount of fPM (*i.e.,* at the current standard of 3.0E–02 lb/MMBtu), and the associated costs for EGUs to comply with the three potential fPM standards. Using this approach, the EPA estimates the cost-effectiveness (based on allowable rather than actual emissions) of control of non-Hg HAP metals to range from $35,400/ton to $49,100/ton for a 1.5E–02 lb/MMBtu emission limit, from $197,000/ton to $238,000/ton for a 1.0E–02 lb/MMBtu emission limit, and $1,610,000/ton for a 6.0E–03 lb/MMBtu emission limit.

The EPA strives to minimize the uncertainty and the costs associated with the measurements used to demonstrate compliance with emission limits. For fPM measurements, the EPA believes that appropriate approaches to minimizing both uncertainty and costs would include limiting sampling times to 3 hours per run and maintaining the random error contribution to the tolerance given to PM CEMS—which is one component of uncertainty—consistent with that of existing fPM emission limits. The impact of sampling times and random errors on measurable emission limits is described in the ''PM CEMS Random Error Contribution by Emission Limit'' memorandum, available in the rulemaking docket. The

[25] See, *e.g.,* Mercury Cell Chlor-Alkali Plants Residual, 87 FR 27002, 27008 (May 6, 2022) (considered annual costs and average capital costs per facility in technology review and beyond-the-floor analysis); Primary Copper Smelting, 87 FR 1616, 1635 (proposed Jan. 11, 2022) (considered total annual costs and capital costs, annual costs, and costs compared to total revenues in proposed beyond-the-floor analysis); Phosphoric Acid Manufacturing and Phosphate Fertilizer Production Phosphate Fertilizer Production Plants and Phosphoric Acid Manufacturing Plants, 80 FR 50386, 50398 (Aug. 19, 2015) (considered total annual costs and capital costs compliance costs and annualized costs for technology review and beyond the floor analysis); Ferroalloys Production, 80 FR 37366, 37381 (June 30, 2015) (considered total annual costs and capital costs, annual costs, and costs compared to total revenues in technology review); Off-site Waste Recovery, 80 FR 14251, 14254 (March 18, 2015) (considered total annual costs and capital costs, and average annual costs and capital costs and annualized costs per facility in technology review); Chromium Electroplating, 77 FR 58225, 58226 (Sept. 19, 2012) (considered total annual costs and capital costs in technology review); Oil and Natural Gas, 77 FR 49490, 49523 (Aug. 16, 2012) (considered total capital costs and annualized costs and capital costs in technology review). *C.f. NRDC* v. *EPA,* 749 F.3d 1055, 1060 (D.C. Cir. 2014 . . .

[26] See Cost TSD for 2022 Proposal at Docket ID No. EPA–HQ–OAR–2018–0794–4620 at *regulations.gov.*

EPA believes that available PM CEMS will be able to accurately measure the proposed fPM emission limit of 1.0E–02 lb/MMBtu, as the average random error contribution is under that of existing emission limits. Although sources have reported fPM values as low as 2.0E–04 lb/MMBtu, given the 3-hour sampling duration and the current fPM detection limit, the EPA currently believes, as described in the memorandum, that some PM CEMS may struggle to meet the EPA's guideline for average random error contribution to the PM CEMS tolerance to demonstrate compliance with a fPM emission limit of 6.0E–03 lb/MMBtu or lower. The EPA solicits comment on the implications for the costs of measuring emissions to demonstrate compliance—whether through stack testing or PM CEMS—of alternate emission limits set at or below 6.0E–03 lb/MMBtu as compared to the proposed fPM emission limit of 1.0E–02 lb/MMBtu, including run durations, fPM detection levels, and random error calculations.

The EPA seeks comment broadly on how we should consider costs in the context of this rule. Taking all of the foregoing discussion into account, the EPA believes that the middle option, a limit of 1.0E–02 lb/MMBtu best balances the critical importance of reducing hazardous emissions pursuant to the EPA's statutory obligations under CAA section 112(d)(6) and ensuring that the worst performers are required to perform at the level of the remainder of the fleet with the costs of doing so in the context of this industry. Considering all the cost metrics, the EPA believes that the cost of the proposed standards is reasonable, and modest in the context of this industry. Based on the foregoing discussion and these analyses, the EPA is proposing to revise the fPM emission limit, as a surrogate for the total non-Hg metal HAP, to 1.0E–02 lb/MMBtu as supported by our analyses of technical feasibility, control costs, cost-effectiveness, and economics. The EPA believes this standard appropriately balances CAA section 112's direction to achieve the maximum degree of emissions reductions while taking into account the statutory factors, including cost. The EPA is further seeking comment on whether a standard of 6.0E–03 lb/MMBtu or lower (for example 2.4E–03 lb/MMBtu, which is the average emission of the best performing 50 percent of units evaluated) would represent a better balancing of the statutory factors.

Indeed, Congress designed CAA section 112 to achieve significant reductions in HAP emissions, which it recognized are particularly harmful pollutants. This proposal is consistent with the EPA's authority pursuant to CAA section 112(d)(6) to take developments in practices, processes, and control technologies into account to determine if more stringent standards are achievable than those initially set by the EPA in establishing MACT floors, based on developments that occurred in the interim. *See LEAN* v. *EPA,* 955 F.3d 1088, 1097–98 (D.C. Cir. 2020). As discussed above in this section, the EPA finds that the vast majority of existing coal-fired EGUs are performing well below the 2012 MATS fPM emission requirements, and that they are achieving these levels at lower costs than the EPA assumed in the 2012 rulemaking. While this proposal in no way refutes that the EPA's initial MACT standards were set at correct levels based on the available information at the time, consistent with CAA section 112's statutory scheme requiring the EPA to regularly revisit those standards, the EPA now proposes to find that more stringent standards are achievable, as chiefly evidenced by the large majority of facilities that are reporting fPM at emission rates well below the current standard.

This proposed emission limit is comparable to the new source standard for fPM in MATS. This proposed emission limit is estimated to reduce non-Hg metal HAP by 6.34 tons per year (and fPM emissions by 2,074 tons/year) at annual costs between $77.3 and $93.2 million. While the 2020 Residual Risk Review concluded that the residual risks are at an acceptable level, Congress required the EPA to conduct technology reviews on an ongoing basis, at least every 8 years, independent of the residual risk review.[27] Moreover, Congress required the EPA to set the standards at the maximum degree of emissions reductions (including prohibition on emissions) that is achievable taking into account the statutory factors. The technological standard approach of CAA section 112 is based on the premise that, to the extent there are controls available to reduce HAP emissions, sources should be required to use them. Since 91 percent of the anticipated capacity of the fleet is already achieving a limit below 1.0E–02 lb/MMBtu, the EPA proposes that this emissions limit level is technologically feasible and demonstrated for a range of control configurations. Additionally, this revised limit would result in significantly lower allowable fPM emissions from the source category compared to the level of emissions allowed by the 2012 MATS Final Rule and help prevent any emissions increases. The EPA does not anticipate any significant non-air health, environmental, or energy impacts as a result of these proposed amendments. Our assessment of control options, costs, and emission reductions is summarized in the memorandum ''2023 Technology Review for the Coal- and Oil-Fired EGU Source Category'' in Docket ID No. EPA–HQ–OAR–2018–0794.

The EPA is not proposing the highest limit examined (1.5E–02 lb/MMBtu) because it would largely leave in place the status quo, in which, despite the proven feasibility and effectiveness of control technologies, a number of sources are lagging far behind. The EPA does not consider a proposed revision to this standard to be consistent with its statutory charge.

While the EPA is not proposing the most stringent limit examined (6.0E–03 lb/MMBtu) or an even more stringent limit, the EPA is taking comment on whether it should consider finalizing such a standard. Such a standard would achieve far more emissions reductions than the emission standards that the EPA is proposing in this action. It would also ensure that the bottom lowest performing quarter of the fleet would have to improve their performance to the level already demonstrated by the remaining three-quarters of the fleet. The EPA declines to propose 6.0E–03 lb/MMBtu as the primary policy option here in light of the above presentation of potential costs, including the EPA's current assessment of measurement uncertainty, when considering the current fleet. These cost estimates are based on the assumption that existing ESP-controlled units would need to install a new FF in order to meet the lower limit, or if existing FF-controlled units do not meet the more stringent limit, those units would need to upgrade their FF bags. If these assumptions are unnecessarily conservative, the total costs and associated cost-effectiveness values may be considerably lower than estimated. The EPA seeks comment on whether there are lower cost compliance options for units with existing ESPs.

An additional factor affecting the total estimated compliance cost is the size and composition of the generating fleet. As noted above, the cost estimates in Table 3 do not account for market and policy developments that are likely to further change the universe of regulated sources and reduce the expected costs of meeting more protective fPM standards. In the likely case that the power sector's transition to lower-emitting generation

[27] See discussion in section V.A, above.

is accelerated by the IRA, for example, the total costs and emissions reductions achieved by each of the three alternative fPM standards shown in Table 3 would also be an overestimate, and the EPA's judgment could change about which standard most appropriately balances CAA section 112's direction to achieve the maximum degree of emissions reductions while taking into account cost and other the statutory factors. The EPA seeks comment on how the IRA and other market and policy developments should inform the Agency's determination.

Additionally, the EPA notes that other future state and federal policies could affect the size, composition, and fPM emissions rate of the future coal-fired EGU fleet. The EPA seeks comment on the extent to which, and how, to take these future policies into account when considering the total cost and cost effectiveness of a more stringent fPM emission limit.

The EPA requests public comment on all aspects of this proposed rule, including our evaluation of the costs and efficacy of control option assumptions. Among other issues, the EPA requests comment on whether we have accurately assessed the variability of fPM emissions and requests information on the costs, pollution reduction benefits, and cost-effectiveness of applying lower emission limits to sources subject to MATS; and whether there are other factors the EPA should consider that would support a lower emission limit, including the contribution that HAP from these sources make to the overall pollution burden. The EPA seeks comment on requiring existing coal-fired EGUs to meet a fPM standard of 6.0E–03 lb/MMBtu or a more stringent standard considering the higher emission reductions as well as the larger total costs such a standard would entail to inform our consideration of whether the more stringent standard would reduce the overall pollution burden in these communities. The EPA also seeks comment on whether there are any areas where EPA has overestimated costs, including some of the generation and storage technologies discussed above as well as the cost of PM controls themselves.

2. PM Emission Monitoring

Under the current rule, EGU owners or operators may choose among quarterly testing, PM CEMS, and PM CPMS to demonstrate compliance with the alternate fPM emission limit in MATS. The initial MATS ICR, available at *www.reginfo.gov,*[28] anticipated that all EGU owners or operators would use PM CEMS for compliance purposes and estimated Equivalent Uniform Annual Cost (EUAC) for the beta gauge PM CEMS to be $65,388. As mentioned in the 2012 proposed Portland Cement NESHAP,[29] beta gauge technology, also referred to as beta attenuation, allows PM CEMS to be much less sensitive to changes in particle characteristics than light-based PM CEMS technologies such as light-scatter or scintillation. Beta attenuation PM CEMS extracts a sample from the stack gas and collects the fPM on filter tape. The device periodically advances the tape from the sampling mode to an area where the sample is exposed to beta radiation. The detector measures the amount of beta radiation emitted by the sample and that amount can be directly related to the mass of the filter. The unannualized purchase cost for a beta gauge PM CEMS and its installation were estimated to be $115,267 in the initial MATS ICR; and the EUAC for beta gauge PM CEMS was estimated to be less expensive than quarterly EPA Method 5 (M5) testing for fPM. Even so, not all EGU owners or operators chose the most cost-effective means of demonstrating compliance with the fPM emission limits. Review of reports submitted to WebFIRE and ongoing ICR renewals shows PM CEMS are used for compliance purposes by about one-third of EGU owners or operators. In addition to being more cost-effective for compliance purposes, PM CEMS provide regulators and the public, as well as the EGU owners or operators, direct and continuous measurement of the pollutant of concern. Such data supply real-time, quality-assured feedback that can lead to improved control device and power plant operation, which, in turn, can lead to fPM emission reductions. Moreover, quick detection of potential problems with PM emissions as provided by PM CEMS, coupled with appropriate corrective measures, can prevent instances of non-compliance, which otherwise could go undetected and uncorrected until the next quarterly PM test. This quicker identification and correction of high emitting EGUs will lead to less pollution emitted and lower pollutant exposure for local communities. In addition to significant value of more efficient pollution abatement, transparency of EGU emissions as provided by PM CEMS, along with real-time assurance of compliance has intrinsic value to the public and communities as well as instrumental value in holding sources accountable.

Since promulgation of MATS, two important developments in the PM CEMS industry have occurred, which the EPA identified as part of this technology review: cessation of beta gauge PM CEMS manufacturing and reduced overall costs for non-beta gauge PM CEMS instruments and installation. These two occurrences have reduced the current one-time costs for PM CEMS, making their use even more cost-effective. As shown in Table 4 below, average non-beta gauge instrument and installation costs obtained from representatives of the Institute of Clean Air Companies (ICAC), a trade association consisting of air pollution control and measurement and monitoring system manufacturers and of environmental equipment and service providers, and from Envea/Altech, a PM CEMS manufacturer and vendor, show about a 48 percent reduction (from $109,420 to $57,095) from average comparable costs determined from the EPA's CEMS Cost Model and Monitoring Cost/Benefit Analysis Tool (MCAT).

TABLE 4—NON-BETA GAUGE PM CEMS COST ESTIMATES USING M5I FOR PS 11

Data source	PM CEMS type	One time costs, $		Annual costs, $				EUAC, $
		Instrument and installation	Other initial costs	Capital recovery	Operation and maintenance	Audits	Other annual costs	
EPA MCAT	In situ	119,295	81,220	22,016	1,558	54,877	11,219	89,670
	Extractive	152,850	81,220	25,700	2,579	54,877	12,241	95,397
EPA CEMS Cost Model	In situ	65,107	79,813	15,912	2,689	54,392	6,525	79,518

[28] See the supporting statement 2137ss06.docx in ICR reference number 201202–2060–005 at OMB Control Number 2060–0567.

[29] See 77 FR 42375, July 18, 2012.

TABLE 4—NON-BETA GAUGE PM CEMS COST ESTIMATES USING M5I FOR PS 11—Continued

Data source	PM CEMS type	One time costs, $		Annual costs, $				EUAC, $
		Instrument and installation	Other initial costs	Capital recovery	Operation and maintenance	Audits	Other annual costs	
	Extractive	100,427	84,458	20,300	3,689	54,392	7,525	85,906
Average		109,420	81,678	20,982	2,629	54,635	9,378	87,623
ICAC	Low	35,000		3,843	12,000	14,290		30,133
	High	40,000		4,392	12,000	14,290		30,682
Envea/Altech	Dry	34,743		3,821		14,290		18,111
	Wet	118,585		13,020		14,290		27,310
Average		57,095		6,269	12,000	14,290		32,559

Generally, EPA models include other initial costs associated with PM CEMS installation, including those associated with planning, selecting equipment, and conducting correlation testing, in its models; such one-time costs are annualized along with instrument and installation costs. The proposed lower fPM emission limit will require longer duration runs for M5 testing and may require the use of M5I, which was designed for PM CEMS correlation testing at low fPM levels. Initial costs in Table 4 for M5I emission testing are $58,000; such testing includes 18 runs of 3-hour duration spread over 9 total days. PM CEMS correlation testing for the proposed lower fPM levels using M5 is estimated to be $41,000. Of course, the quarterly testing run durations would need to increase if PM CEMS were not used; annual cost for M5 testing with 3 hour run duration is estimated to be $85,127 ($82,000 for testing, and $3,127 for 24 hours of site technical support); quarterly testing using M5I with runs of similar duration is estimated to be $107,127. However, neither ICAC nor Envea/Altech explicitly included those costs as line items in their estimates. This does not necessarily mean that such costs have been excluded; if such costs have been included, then the estimates do not change, but if such costs have not been included, the estimates may increase. Their average capital recovery cost, determined from the sum of the instrument, installation, and other initial costs amortized over 15 years at a 7 percent interest rate, is about 70 percent lower than that obtained from the average capital recovery cost obtained from the EPA models. As shown in the table, EPA models also include annual costs for operation and maintenance, relative response and correlation audits, and other items such as reporting and recordkeeping. The sum of those items plus the capital recovery cost yields EUAC of PM CEMS. ICAC includes operation and maintenance as a line item in its annual costs, but neither ICAC nor Envea/Altech include audits or other items in their annual costs estimates. Because EPA believes some EGUs may require PM spiking—an approach that involves introducing known amounts of fPM to increase fPM concentration without altering control device equipment—the EPA added $14,290 (the annualized cost of conducting $35,000 p.m. spiking every 3 years at an interest rate of 7 percent) to the audit portion of all entries. As mentioned earlier, omission of specifically named costs does not necessarily mean that those costs have been excluded; rather these costs may be included in other listed costs. Using the data provided and explained above, the average EUAC for PM CEMS that rely on M5I correlation testing is about 63 percent lower than the average EUAC from EPA models (from $87,623 to $32,559). Given that the annual cost of quarterly M5 testing for fPM is now estimated to be $85,127, annualized other one-time costs and operation and maintenance, audits, and other annualized costs—if omitted by the manufacturers—would have to be more than $52,568 for PM CEMS to be less cost-effective than quarterly testing.

As mentioned in the proposed Portland Cement NESHAP from 10 years ago (see 77 FR 42374, July 18, 2012), the EPA was aware of the potential difficulty use of PM CEMS might have created in determining compliance for that rulemaking due to the low end of emission limits (0.04 lb/ton clinker, which translates to a range of about 5 to 8 mg/dscm, depending on particle characteristics) and to the short duration of emission test runs. The EPA addressed those concerns for that rulemaking by proposing to raise the emission limit to 0.07 lb/ton clinker, which translated to a range of about 7 to 14 mg/dscm, and to no longer require PM CEMS use; instead, owners or operators would use their PM CEMS as PM CPMS. Even so, the durations of test runs used to develop the correlation of the instrument with the emissions limit remained unchanged, at about 1 hour per run. Such short run durations led to inherent measurement uncertainty accounting for more than half the emission limit at the expected portland cement plant operating condition, leading some to question whether values provided by instrumentation were appropriately related to emissions.

The conditions experienced by portland cement facilities that required revisions to emission limits and compliance determination method are not similar to those expected to be faced by EGU owners or operators subject to MATS. First, the fuel used by coal-fired EGUs is more uniform and its characteristics are more consistent than those of the fuel and additive mixtures used by portland cement kilns. Such fuel combustion particle consistency allows technologies such as light scattering and scintillation, in addition to beta gauges, to be used by PM CEMS for compliance determination purposes. Moreover, consistent fPM particle characteristics for EGUs provide stable correlations for those EGUs with existing PM CEMS; while the fPM particle characteristics provide correlations that remain within specifications, as evidenced by ongoing relative correlation audits, the existing correlations do not change and can continue to be used now and in the future without having to develop a new correlation. Second, the proposed MATS emission limit of 1.0E–02 lb/MMBtu, which translates to about 7.3 mg/dscm, coupled with a minimum sampling collection time of 3 hours per run, based on a typical sampling rate of ¾ cubic feet per minute, avoids the measurement problems described by the Portland Cement NESHAP by reducing the average inherent measurement uncertainty for half of the proposed emission limit (where the EGU is expected to operate) from more than 50 to 80 percent. In addition, use of 3 hour run durations would allow for a 6.0E–03 lb/MMBtu (or about 4.4 mg/dscm) MATS emission limit, which the EPA is seeking comment on, to have an average inherent measurement uncertainty due to random error of 14 percent at the target PM CEMS operational limit of 3.0E–03 lb/MMBtu. As shown, inherent measurement uncertainty does not appear to be problematic for the primary proposed emission limit, but, as mentioned earlier, some PM CEMS may have difficulty meeting the inherent measurement uncertainty—specifically, the average random error component—of the alternative proposed emission limit. Note that the primary proposed MATS emission limit is just above the fPM limit for new EGUs, as 9.0E–02 lb/MWh on an electrical output basis translates to about 9.0E–03 lb/MMBtu on a heat input basis. MATS requires use of PM CEMS for new EGUs, along with minimum sampling collection time of 3 hours per run.[30] Proposed use of runs of at least 3 hour durations and emission limits of 1.0E–02 lb/MMBtu would be consistent with run durations and limits already in MATS. Third, Performance Specification 11 (PS 11), which provides procedures and acceptance criteria for validating PM CEMS technologies, already anticipates and includes approaches for developing low-level emission correlations for PM CEMS. Those techniques include varying process operations; varying fPM control device conditions; PM spiking zero point methods when the previous techniques are not able to provide the 3 distinct fPM concentration levels. As mentioned earlier, average costs for fPM spiking are about $35,000 every 3 years, or $14,290 annually at an interest rate of 7 percent, and not every EGU will need to adjust its existing correlation in order to continue to use its existing PM CEMS to demonstrate compliance with the proposed limits; however, for purposes of this proposal, costs for spiking will be included in annual PM CEMS cost estimates. In addition to these techniques to aid PM CEMS use for rules with low level emissions, the EPA is aware that the Electric Power Research Institute (EPRI) began working with an instrument manufacturer in 2009, prior to MATS promulgation, to develop a National Institute of Standards and Technology (NIST) traceable aerosol generator that injects known particle size distribution and mass into PM CEMS. Such an instrument, known as a Quantitative Aerosol Generator (QAG), would allow direct PM CEMS calibration, as opposed to the development of a curve that provides a correlation for the PM CEMS.[31] That study relied on six emission rates, four of which were at or under 5 mg/dscm, and reported successful sample collection and transport. EPRI continued this work and provided a technical update in 2014,[32] but the EPA is unaware of specific recommendations or suggestions regarding QAG application to PM CEMS. While we believe the use of the QAG could lower fPM monitoring costs for PM CEMS use, we seek more information on its application for lower fPM limits as measured by PM CEMS; specifically, we solicit comment on whether implementation of the QAG is another reason that PM CEMS costs have decreased.

For these reasons, we propose to require the use of PM CEMS as the method to demonstrate compliance with the fPM emissions limit for coal-fired and IGCC EGUs pursuant to the EPA's authority under CAA section 112(d)(6). If our proposal is finalized, EGU owners or operators currently relying on quarterly PM emissions testing would need to install, operate, and maintain PM CEMS. Such a switch is projected to be more cost-effective, more informative, and more effective in assuring compliance than use of quarterly testing. Those EGU owners or operators already using PM CEMS as their means of compliance determination would maintain their current approach; while some may have no need for additional expenditures, the proposal includes the costs associated with revised and ongoing correlation testing and spiking for all EGUs. Since a proposed requirement for use of PM CEMS renders the current compliance option for the LEE program superfluous, the EPA proposes to remove the individual and total non-Hg metal HAP and the surrogate fPM from the LEE program for all MATS-affected EGUs and solicits comments on removing these limits.

The EPA seeks comment on distinctions between portland cement plants and EGUs that would facilitate PM CEMS use at EGUs. Specifically, the EPA seeks comment on the ability, type, and capabilities of PM CEMS to accurately measure fPM emissions at the levels proposed in this rule. Moreover, the EPA seeks comment on additional or other approaches that could be employed to facilitate PM CEMS use for the proposed emission levels. Specific comments on direct PM CEMS calibration methods, such as the QAG, as well as limitations, are welcome.

The EPA solicits comment on the availability of beta gauge instruments, on the current average costs of non-beta gauge PM CEMS instruments and installation, on ICAC's annual costs, and on Envea/Altech's annual costs. When commenting on EPA model estimates or ICAC's or Envea/Altech's estimates, please provide specific PM CEMS instrument type, manufacturer, and model; cost information broken down by initial cost including instrument type and installation cost, and annual cost, including operation and maintenance, audit, and other costs in your comments. Moreover, please identify in your comments specific items included in your cost information, such as installation, operation, and maintenance provisions. The EPA also solicits comment on the cost-effectiveness of PM CEMS as compared to quarterly PM emissions testing. Also, the EPA solicits comment on the availability of PM CEMS and their use for compliance purposes, especially when compared to less frequent, more expensive measures.

The EPA is aware that some EGUs may be on enforceable schedules to cease operations, which may be just beyond the three-year compliance date the EPA proposes for PM CEMS monitoring requirements in section V.E, below, and that owners or operators of EGUs may be unable to recoup investments in PM CEMS if the instruments are not in operation for at least a certain period of time beyond their installation date. Therefore, the EPA seeks comment on whether EGUs should be able to continue to use quarterly emissions testing past the proposed compliance date for a certain period of time or until EGU retirement, whichever occurs first, provided the EGU is on an enforceable schedule for ceasing coal- or oil-fired operation. In addition, the EPA seeks comment on what would qualify as an enforceable schedule, such as that contained in the Agency's ''EGUs Permanently Ceasing Coal Combustion by 2028'' included in the 2020 Steam Electric ELG Reconsideration Rule (85 FR 64640, 64679, and 64710; 10/13/2020), as well as what the maximum duration of operation using quarterly emissions testing for compliance purposes should be.

[30] See Table 1 to subpart UUUUU of 40 CFR part 63. At a typical sampling rate of ¾ cubic foot per minute, a run would require 3 hours to collect at least 4 cubic meters of sample.

[31] See *A Qualitative Aerosol Generator Designed for Particulate Matter (PM) Continuous Emissions Monitoring Systems (CEMS) Calibration,* available at *www.epri.com/research/products/1017574.*

[32] See *Quantitative Aerosol Generator (QAG) for Calibration of Particulate Monitors: 2014 Technical Update,* available at *www.epri.com/research/products/3002003343.*

3. Review of the Hg Emission Standards

a. Overview of Hg Emissions From Combustion of Coal

Mercury is a naturally occurring element found in small and varying quantities in coal. During combustion of coal, Hg is volatilized and converted to elemental Hg vapor (Hg^0) in the high temperature regions of the boiler. Hg^0 vapor is difficult to capture because it is typically nonreactive and insoluble in aqueous solutions. However, under certain conditions, the Hg^0 vapor in the flue gas can be oxidized to divalent Hg (Hg^{2+}). The Hg^{2+} can bind to the surface of solid particles (*e.g.,* fly ash) in the flue gas stream, often referred to as ''particulate bound Hg'' (Hg_p), and be removed in a downstream PM control device. Oxidized Hg compounds can also be soluble and can be removed in a wet scrubber. The presence of chlorine in gas-phase equilibrium favors the formation of mercuric chloride ($HgCl_2$) at flue gas cleaning temperatures. However, Hg^0 oxidation reactions are kinetically limited as the flue gas cools and, as a result, Hg often enters the flue gas cleaning device(s) as a mixture of Hg^0, Hg^{2+} compounds, and Hg_p. This partitioning into various species of Hg has considerable influence on selection of Hg control approaches. In general, because of the presence of higher amounts of halogen (especially chlorine) in bituminous coals, most of the Hg in the flue gas from bituminous coal-fired boilers is in the form of Hg^{2+} compounds, typically $HgCl_2$ and is more easily captured in downstream control equipment. Conversely, both subbituminous coal and lignite have lower halogen content, compared to that of bituminous coals, and the Hg in the flue gas from boilers firing those fuels tends to be in the form of Hg^0 and is more challenging to control in downstream control equipment.

Fly ash is typically classified as acidic (pH less than 7.0), mildly alkaline (pH greater than 7.0 to 9.0), or strongly alkaline (pH greater than 9.0). The pH of the fly ash is usually determined by the calcium/sulfur ratio and the amount of halogen. The ash from bituminous coals tends to be acidic due to the relatively higher sulfur and halogen content and the glassy (nonreactive) nature of the calcium present in the ash. Conversely, the ash from subbituminous and lignite coals tends to be more alkaline due to the lower amounts of sulfur and halogen and a more alkaline and reactive (non-glassy) form of calcium in the ash. The natural alkalinity of the subbituminous and lignite fly ash can effectively neutralize the limited free halogen in the flue gas and prevent oxidation of the Hg^0.

Some coal-fired power plants—especially those firing bituminous coal—achieve some level of Hg emissions control using existing equipment that was installed to remove other pollutants, including PM, SO_2, and nitrogen oxides (NO_X). Particulate-bound Hg (Hg_p) is effectively removed along with PM in PM control equipment such as FFs and ESPs. Soluble Hg^{2+} compounds (such as $HgCl_2$) can be effectively captured in wet FGD systems. And, while a selective catalytic reduction (SCR) system that has been installed for NO_X control does not itself capture Hg, it can under the right conditions enhance the oxidation of Hg^0 in the flue gas for increased Hg removal in a downstream PM control device or in a wet FGD scrubber.

However, because the Hg in their flue gas tends to be present in the non-reactive Hg^0 phase, EGUs firing subbituminous coal or lignite often get little to no control from equipment designed and installed for other pollutants. While some bituminous coal-fired EGUs require use of additional Hg-specific control technology, such as injection of a sorbent or chemical additive, to supplement the control that these units already achieve from criteria pollutant control equipment, these Hg-specific control technologies are often required as part of the Hg emission reduction strategy at EGUs that are firing subbituminous coal or lignite. As mentioned, the Hg in the flue gas for those EGUs tends to be in the non-reactive Hg^0 phase due to lack of free halogen to promote the oxidation reaction. To alleviate this challenge, activated carbon and other sorbent providers and control technology vendors developed methods to introduce halogen into the flue gas to improve the control of Hg emissions from EGUs firing subbituminous coal and lignite. This was primarily through the injection of pre-halogenated (often pre-brominated) activated carbon sorbents or through the injections of halogen-containing chemical additives along with conventional sorbents. This challenge to controlling Hg emissions was a challenge for EGUs firing subbituminous coal and for EGUs firing lignite.

b. Hg Emission Standards in the 2012 MATS Final Rule

In the 2012 MATS Final 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. See 77 FR 9304, February 16, 2012. The EPA established a final Hg emission standard of 4.0 pounds of Hg per trillion British thermal units of heat input (lb Hg/TBtu) for lignite-fired utility boilers. The EPA promulgated a final Hg emission standard for EGUs firing non-lignite coals, including bituminous and subbituminous coal, of 1.2 lb Hg/TBtu.

Under CAA section 112(d)(1), the Administrator has the discretion to ''distinguish among classes, types, and sizes of sources within a category or subcategory'' in establishing standards. Any basis for subcategorization must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the units. See 76 FR 25036–25037.

When developing the MATS rule, the EPA examined available Hg emissions data from coal-fired EGUs and found that there were no lignite-fired EGUs among the top performing 12 percent. The EPA then determined that the difference in the emissions from the lignite-fired EGUs was due to a difference in the class, type, or size of those units and finalized two subcategories of coal-fired EGUs for Hg emissions. See 76 FR 25036–67. The EPA considered basing the subcategory definition solely on an EGU (1) being designed to burn lignite and (2) burning lignite. However, the EPA decided not to do so because of the concern that such a definition would allow sources to potentially meet the definition by combusting very small amounts of low rank virgin lignite. In the preamble of the 2012 MATS Final Rule, the EPA suggested a scenario where an EGU that was not designed to burn lignite and did not routinely burn lignite could import one truck full of low rank virgin coal and burn a very small quantity of it periodically to meet the subcategory definition. To avoid creating this potential loophole, the EPA also finalized a requirement that the unit be constructed and operated at or near a mine containing the low rank virgin coal it burns. The EPA indicated that the final definition would prevent other EGUs that are not firing lignite from complying with the less stringent Hg emission standard. The final definition, as specified in the 2012 MATS Final Rule (77 FR 9369, February 16, 2012), was: ''*Unit designed for low rank virgin coal* subcategory means any coal-fired EGU that is designed to burn and that is burning non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.''

c. Beyond-the-Floor Analysis for the 2012 MATS Final Rule

For the 2012 MATS Final Rule, the EPA calculated beyond-the-floor costs for Hg controls by assuming injection of brominated activated carbon at a rate of 3.0 pounds of sorbent per million actual cubic feet of flue gas (lb/MMacf) for lignite-fired EGUs with an ESP for PM control and at an injection rate of 2.0 lb/MMacf for lignite-fired units with a baghouse (also known as a fabric filter, FF). The sorbent injection rate of 2.0 lb/MMacf for lignite-fire units with FFs is consistent with the rate assumed for all other coal types. The EPA assumed a sorbent injection rate of 3.0 lb/MMacf for lignite-fired units with ESPs, which is lower than the sorbent injection rate of 5.0 lb/MMacf that the EPA assumed for EGUs firing using other (non-lignite) coal types. In the Beyond-the-Floor Memo (see Docket ID No. EPA–HQ–OAR–2009–0234–20130), the EPA indicated that this lower sorbent injection rate was appropriate, because a higher rate would likely result in Hg emission reductions greater than those needed to meet the beyond-the-floor standard of 4.0 lb/TBtu noting that greater than 90 percent control can be achieved at lignite-fired units at a 2.0 lb/MMacf injection rate for units with installed FF and using treated (*i.e.,* brominated) activated carbon or at an injection rate of 3.0 lb/MMacf for units using treated activated carbon with installed ESPs.

Petitioners challenged the beyond-the-floor standard for lignite-fired EGUs, claiming that the final standard is not achievable because they asserted that the standard would require unrealistically high levels of Hg reduction. In *White Stallion* v. *EPA,* the Court of Appeals of the District of Columbia Circuit rejected petitioners' challenge to the final beyond-the-floor standard on the basis that the EPA had adequately concluded during the rulemaking process that the standard for lignite units were achievable if sources increased their use of a particular control technology, ACI. *See White Stallion Energy Center, LLC* v. *EPA,* 748 F.3d 1222, 1251 (D.C. Cir. 2014).

d. Hg Emission Reductions Since Promulgation of the 2012 MATS Final Rule

The EPA estimated annual Hg emissions from coal-fired power plants in 2010 (pre-MATS) to be 29 tons.[33] In 2017, after full implementation of the MATS rule, the EPA estimated Hg emissions had been reduced to 4 tons, an 86 percent decrease.[34] This decline was due to the installation and use of Hg controls as well as other significant changes in the power sector (*e.g.,* coal plant retirements, increase use of natural gas and renewable energy, *etc.*) in the same time period.

i. Hg Emissions From Coal-Fired EGUs in 2021

Hg emission reductions have continued to decline since 2017 as more coal-fired EGUs have retired or reduced utilization. The EPA estimated that 2021 Hg emissions from coal-fired EGUs were 3 tons (a 90 percent decrease compared to pre-MATS levels).[35] However, units burning lignite coal (or permitted to burn lignite) accounted for a disproportionate amount of the total Hg emissions in 2021. As shown in Table 5 below, 16 of the top 20 Hg-emitting EGUs were lignite-fired EGUs. Overall, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs in 2021, while generating about 7 percent of total 2021 megawatt-hours. Lignite accounted for 8 percent of total U.S. coal production in 2021.

TABLE 5—TOP HG-EMITTING EGUS IN 2021

Rank	EGU	Fuel	2021 Hg emissions (lb)	State
1	Coal Creek 2	Lignite	181.8	ND
2	Coal Creek 1	Lignite	175.6	ND
3	Oak Grove 2	Lignite	149.8	TX
4	Martin Lake 3	Lignite/Subbituminous	134.4	TX
5	Oak Grove 1	Lignite	112.7	TX
6	Martin Lake 2	Lignite/Subbituminous	111.0	TX
7	Milton R Young B2	Lignite	103.1	ND
8	Martin Lake 1	Lignite/Subbituminous	100.7	TX
9	Antelope Valley B2	Lignite	89.8	ND
10	Coyote B1	Lignite	79.9	ND
11	H W Pirkey Power Plant 1 *	Lignite/Subbituminous	71.1	TX
12	Antelope Valley B1	Lignite	69.6	ND
13	San Miguel SM–1	Lignite	64.6	TX
14	Sandy Creek Energy Station S01	Subbituminous	53.5	TX
15	Limestone LIM2	Lignite/Subbituminous	52.5	TX
16	Milton R Young B1	Lignite	52.4	ND
17	Comanche 3	Subbituminous	50.3	CO
18	Leland Olds 2	Lignite	50.1	ND
19	James H Miller Jr 3	Subbituminous	42.9	AL
20	Labadie 2	Subbituminous	42.5	MO

* This unit has announced its intention to retire in 2023.

ii. Limited CAA Section 114 Request

In May 2021, pursuant to authority in section 114 of the CAA, 42 U.S.C. 7414(a), the EPA solicited information related to Hg emissions and Hg control technologies from certain lignite-fired EGUs to inform this CAA section 112(d)(6) technology review. The selected lignite-fired EGUs were asked

[33] Memorandum: Emissions Overview: Hazardous Air Pollutants in Support of the Final Mercury and Air Toxics Standard. EPA–454/R–11–014. November 2011; Docket ID No. EPA–HQ–OAR–2009–0234–19914.

[34] 2017 Power Sector Programs Progress Report; available at *https://www.epa.gov/sites/default/files/2019-12/documents/2017_full_report.pdf* and in the rulemaking docket.

[35] 2021 Power Sector Programs Progress Report; available at *https://www3.epa.gov/airmarkets/progress/reports/pdfs/2021_full_report.pdf* and in the rulemaking docket.

to provide information on their control configuration for Hg and for other air pollutants (*e.g.,* criteria pollutants such as PM, NO_X, SO_2). Selected information on lignite-fired EGU control configurations that was obtained from the CAA section 114 information request is shown below in Table 6. Additional information on the location, size (capacity), firing configuration, and control configuration of lignite-fired EGUs (including those few that were not included in the CAA section 114 information request) is also included. The additional information was obtained from the EPA's NEEDS database.[36]

TABLE 6—CONTROL CONFIGURATIONS FOR LIGNITE-FIRED EGUS

Plant name	State	Capacity (MW)	Firing	Control configuration	Hg control description	Hg control
Antelope Valley #1 Antelope Valley #2	ND ND	450 450	tangent tangent	ACI + SDA + FF ACI + SDA + FF.	Does not use activated carbon as its sorbent, instead injects a liquid sorbent to the scrubber. The facility stopped using refined coal in December 2021.	Nalco non-carbon, non-halogenated liquid sorbent added to dry scrubber; M-Sorb additive (bromide).
Coal Creek #1 Coal Creek #2	ND ND	574 573	tangent tangent	ACI + ESPC + WFGD ACI + ESPC + WFGD.	Information not collected in the CAA 114 request.	
Coyote	ND	429	cyclone	ACI + SDA + FF	Information not collected in the CAA 114 request.	
Leland Olds #1 Leland Olds #2	ND ND	222 445	wall cyclone	SNCR + ACI + ESPC + WFGD. SNCR + ACI + ESPC + WFGD.	Activated carbon and oxidizer injections for Hg control.	ME2C SEA SF10 Oxidizer and SB24 Activated Carbon.
Milton R Young #1 Milton R Young #2	ND ND	237 447	cyclone cyclone	SNCR + ACI + ESPC + WFGD. SNCR + ACI + ESPC + WFGD.	Hg controlled by Powdered Activated Carbon Injection plus Oxidizing Agent/Halogen Injection System.	DARCO Hg-H non-halogenated Powdered Activated Carbon + ADA M-Prove additive.
Spiritwood Station	ND	92	FBC	SNCR + ACI + SDA + FF.	Hg emissions are controlled by activated carbon injection system and a CEMS. The activated carbon injection feed rate is adjusted to maintain emissions below the 4.0 lb/TBtu standard.	Activated Carbon sorbent (not specified).
Limestone #1 Limestone #2	TX TX	831 858	tangent tangent	SNCR + ACI + ESPC + WFGD. SNCR + ACI + ESPC + WFGD.	Information not collected in the CAA 114 request.	
Major Oak #1 Major Oak #2	TX TX	152 153	FBC FBC	Reagent Injection + SNCR + ACI + FF. Reagent Injection + SNCR + ACI + FF.	Hg is controlled by the introduction of activated carbon into each boiler duct directly in front of the baghouse. A halogen fuel additive is also applied to the lignite before it enters the day silos.	Cabot DARCO Hg-H non-Brominated AC + ADA–ES M-Prove additive.
Martin Lake #1 Martin Lake #2 Martin Lake #3	TX TX TX	800 805 805	tangent tangent tangent	ACI + ESPC + WFGD ACI + ESPC + WFGD. ACI + ESPC + WFGD.	Brominated additive injected into the furnace and activated carbon injected upstream of the air heater. In 2020 and 2021 Refined Coal System applied an aqueous bromine salt solution to the coal.	ME2C SEA process (non-Brominated AC + chemical additive).
Oak Grove #1 Oak Grove #2	TX TX	855 855	tangent wall	SCR + ACI + FF + WFGD. SCR + ACI + FF + WFGD.	Brominated activated carbon injected downstream of the air heater. From 2018 to 2021, the unit was equipped with a Refined Coal System for Hg control. This system applied an aqueous bromine salt solution to the coal downstream of the crusher. The refined coal system is no longer in service.	ADA–CS Br–AC.
Red Hills #1 Red Hills #2	MS MS	220 220	FBC FBC	Reagent Injection + ACI + FF. Reagent Injection + ACI + FF.	Hg is controlled by injection of activated carbon into each boiler duct directly in front of the baghouse. A fuel additive is also applied to the lignite before it enters the day silos. The application of fuel additives ended in December 2021.	ADA–CS non-Br AC + ADA–ES M45 liquid additive.

[36] National Electric Energy Data System (NEEDS) v621 rev: 10–14–22, available at: *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6.*

TABLE 6—CONTROL CONFIGURATIONS FOR LIGNITE-FIRED EGUS—Continued

Plant name	State	Capacity (MW)	Firing	Control configuration	Hg control description	Hg control
San Miguel	TX	391	wall	SNCR + ACI + ESPC + WFGD.	Hg is captured using a sorbent enhanced additive (SEA) injected onto the lignite at the pulverizer feeders or directly into the furnace to promote the oxidation and capture of Hg. This is followed by an ACI system located in the boiler exit duct work upstream of the air heaters. The scrubber system also reduces Hg emissions.	ME2C SEA process (non-Br AC + powder-based chemical additive).

Note: ACI = activated carbon injection; SDA = spray dryer absorber (dry scrubber); FF = fabric filter; ESPC = cold side electrostatic precipitator; WFGD = wet flue gas desulfurization scrubber; SNCR = selective non-catalytic reduction (NO_X control); reagent injection = sorbent injection into fluidized bed combustor.

Most, but not all, of the EGUs utilized a combination of the use of a chemical additive and injection of a sorbent as their Hg control strategy. One facility in North Dakota (Antelope Valley) uses a liquid sorbent that is injected to the SO_2 scrubber (spray dryer absorber, SDA). Many of the EGUs used ''refined coal.'' Refined coal is typically produced by mixing proprietary additives to feedstock coal to help capture emissions when the coal is burned. For example, these additives may promote the oxidation of Hg to Hg^{2+} compounds for capture in downstream control equipment (*e.g.,* FGD scrubbers, PM control devices). Several of the facilities noted that use of refined coal as a part of their Hg control strategy was discontinued at the end of 2021 when the refined coal production tax credit (created by the American Jobs Creation Act of 2004) expired. According to a U.S. Government Accountability Office audit report, refined coal producers claimed approximately $8.9 billion in tax credits between 2010 and 2020.

According to fuel use information supplied to EIA (on form 923), 13 of 22 EGUs that were designed to burn lignite utilized refined coal to some extent in 2021, as summarized in Table 7. EIA form 923 does not specify the type of coal that is ''refined'' when reporting boiler or generator fuel use. For this technology review, the EPA has assumed that the facilities have utilized ''refined lignite,'' as reported in fuel receipts on EIA form 923. However, several ''lignite-fired EGUs'' located in Texas reported very high use of subbituminous coal in 2021 (ranging from 76 percent up to > 99 percent).

TABLE 7—2021 FUEL USE AT LIGNITE-FIRED EGUS

Plant name	Distillate fuel oil (%)	Natural gas (%)	Lignite coal (%)	Refined coal (%)	Subbituminous coal (%)
Antelope Valley 1	0.0	0.6	5.8	93.5	0.0
Antelope Valley 2	0.0	0.6	5.8	93.5	0.0
Coal Creek 1	0.1	0.0	0.0	99.9	0.0
Coal Creek 2	0.1	0.0	0.0	99.9	0.0
Coyote 1	0.3	0.0	99.7	0.0	0.0
Leland Olds 1	0.3	0.0	37.6	62.1	0.0
Leland Olds 2	0.3	0.0	6.2	93.6	0.0
Milton R Young 1	0.4	0.0	17.0	82.6	0.0
Milton R Young 2	0.2	0.0	12.1	87.6	0.0
Spiritwood Station 1	0.0	35.6	0.0	64.4	0.0
Limestone 1	0.0	0.2	0.0	0.0	99.8
Limestone 2	0.0	0.8	0.0	0.0	99.2
Major Oak Power 1	0.0	0.2	99.8	0.0	0.0
Major Oak Power 2	0.0	0.0	100.0	0.0	0.0
Martin Lake 1	0.1	0.0	23.5	0.0	76.4
Martin Lake 2	0.1	0.0	22.4	0.0	77.5
Martin Lake 3	0.1	0.0	19.2	0.0	80.6
Oak Grove 1	0.0	1.9	3.4	94.7	0.0
Oak Grove 2	0.0	0.0	3.7	96.3	0.0
Red Hills Generating Facility 1	0.0	0.3	0.0	99.7	0.0
Red Hills Generating Facility 2	0.0	0.3	0.0	99.7	0.0
San Miguel 1	0.2	0.0	99.8	0.0	0.0

e. CAA Section 112(d)(6) Technology Review of the Hg Standards

i. Review of the Hg Emission Standard for Non-Lignite-Fired EGUs

The final MATS Hg emission limit for EGUs firing non-lignite coals (*i.e.,* bituminous and subbituminous coals) is 1.2 lb Hg/TBtu. To review that emission standard, the EPA evaluated the 2021 performance of EGUs firing non-lignite coals and found that EGUs firing primarily bituminous coal emitted Hg at an average annual rate of 0.4 lb Hg/TBtu (with a range of roughly 0.2 to 1.2 lb Hg/TBtu). EGUs firing primarily subbituminous coal in 2021 (not including those EGUs that are permitted to burn lignite but burned a significant amount of subbituminous coal) emitted Hg at an average annual rate of 0.6 lb Hg/TBtu (with a range of 0.1 to 1.2 lb/TBtu). This represents a control range of 98 to 77 percent (assuming an average inlet concentration of 5.5 lb/TBtu). The EPA has information on the control configurations of these non-lignite

EGUs. However, because the non-lignite-fired EGUs were not included in the limited CAA section 114 information collection, the EPA does not have detailed information on the type of sorbent injected (*e.g.,* activated carbon or non-carbonaceous; pre-halogenated, *etc.*). The EPA also does not have detailed information on the injection rate of sorbents used for Hg control (if any). Similarly, the EPA does not have information on the type of quantity of chemical additives used (if any). However, the bituminous coal-fired EGUs are already achieving an average annual rate of 0.4 lb/TBtu and the subbituminous coal-fired EGUs are already achieving an average annual rate of 0.6 lb/TBtu. The typical Hg control performance curves for sorbent injection show a leveling off such that increasing the amount of sorbent results in diminishing improvement in Hg control. Based on full-scale demonstration testing of Hg sorbents, this leveling off typically takes place somewhere greater than 90 percent capture. Without knowing the type of sorbent being injected or the rate of the sorbent injection, it is difficult to determine whether additional emission reductions could be achieved in a cost-effective manner. For bituminous coal-fired EGUs that do not utilize sorbent injection but rely on co-benefit control from equipment installed for criteria pollutants, it is difficult to determine whether additional Hg emission reduction could be obtained in a cost-effective manner with knowledge of the levels of Hg control achieved in each of the installed controls and, if chemical additives are injected, the type and rate of chemical additive injection. For those reasons, the EPA is not proposing to adjust the Hg emission standard for non-lignite-fired EGUs at this time. However, the EPA solicits comment on the performance of Hg controls for non-lignite-fired EGUs, including information on the type and injection rate of sorbents used for Hg control, as well as the possibility of additional cost-effective measures to further reduce Hg from equipment installed for criteria pollutants. The EPA also seeks comment on whether there would be a reasonably efficient way to more thoroughly survey the types of controls—including the types of sorbents used and their injection rates—used to limit Hg emissions at non-lignite-fired EGUs, and whether conducting such additional information collection would be worthwhile.

In addition, the EPA notes that several states have adopted Hg reduction standards that go beyond the 2012 MATS Final Rule in their reduction target. For instance, Connecticut, Minnesota, Montana, New York, Oregon, and Utah all established input-based Hg limits below 1.2 lb/TBtu. For further detail on all 18 states with existing Hg emissions limits, see Chapter 3 of EPA's IPM documentation, available in the docket. The EPA solicits information about the cost and effectiveness of control strategies that EGUs in these states utilize to meet more stringent Hg emission standards than those promulgated in the 2012 MATS Final Rule, as well as any other available control strategies that the EPA should consider and their costs.

ii. Review of the Hg Emission Standard for Lignite-Fired EGUs

The final MATS Hg emission limit for EGUs firing lignite coal is 4.0 lb Hg/TBtu—more than three times the standard for non-lignite coal. To review that emission standard, the EPA evaluated the data obtained in the 2022 CAA section 114 data survey along with the emissions data reported to the EPA and the fuel use data submitted to EIA. The 2021 performance of lignite-fired EGUs (including those permitted to burn lignite but that utilized significant amounts of subbituminous coal in 2021) is shown in Table 8 below. The table shows a ''Hg Inlet'' level which reflects the maximum Hg content of the range of feedstock coals that the EPA assumes is available to each of the plants in the Integrated Planning Model, IPM,[37] the estimated control (percentage) needed to meet an emission standard of 4.0 lb Hg/TBtu (the current standard for lignite-fired EGUs) and the estimated control (percentage) to meet an emission standard of 1.2 lb Hg/TBtu (the current standard for non-lignite-fired EGUs). The table also shows the estimated 2021 Hg inlet concentration from actual 2021 fuel usage (as mentioned earlier, some units utilized significant quantities of non-lignite fuel, *e.g.,* subbituminous coal, natural gas, *etc.*) and the 2021 Hg emissions reported to the EPA. The EPA then estimated the apparent level of Hg control for 2021 and the level of control that would been needed to achieve the emission standard applicable to the non-lignite-firing EGUs (1.2 lb Hg/TBtu).

TABLE 8—HG EMISSIONS AND CONTROL PERFORMANCE OF LIGNITE-FIRED EGUS IN 2021

Plant name	Hg inlet (lb/TBtu)	Est Hg control at 4.0 lb/TBtu (%)	Est Hg control at 1.2 lb/TBtu (%)	Est 2021 Hg inlet (lb/TBtu)	2021 Hg outlet (lb/TBtu)	Est 2021 Hg control (%)	Est 2021 Hg control at 1.2 lb/TBtu (%)
Antelope Valley #1	7.81	48.8	84.6	7.76	2.87	63.0	84.5
Antelope Valley #2	7.81	48.8	84.6	7.76	2.74	64.6	84.5
Coal Creek #1	7.81	48.8	84.6	7.80	3.62	53.6	84.6
Coal Creek #2	7.81	48.8	84.6	7.80	3.89	50.2	84.6
Coyote	7.81	48.8	84.6	7.79	3.17	59.2	84.6
Leland Olds #1	7.81	48.8	84.6	7.79	2.51	67.8	84.6
Leland Olds #2	7.81	48.8	84.6	7.79	3.02	61.3	84.6
Milton R Young #1	7.81	48.8	84.6	7.78	3.23	58.4	84.6
Milton R Young #2	7.81	48.8	84.6	7.79	3.20	58.9	84.6
Spiritwood Station	7.81	48.8	84.6	5.03	1.86	63.1	76.1
Limestone #1	14.88	73.1	91.9	6.24	0.94	84.9	80.8
Limestone #2	14.88	73.1	91.9	6.20	1.59	74.4	80.7
Major Oak #1	14.65	72.7	91.8	14.62	1.24	91.5	91.8
Major Oak #2	14.65	72.7	91.8	14.65	1.31	91.1	91.8
Martin Lake #1	14.65	72.7	91.8	8.22	2.32	71.8	85.4
Martin Lake #2	14.65	72.7	91.8	8.13	2.99	63.2	85.2
Martin Lake #3	14.65	72.7	91.8	7.85	3.04	61.3	84.7

[37] Discussion of how these assumptions were developed for use in the EPA's IPM modeling is available in Chapter 7 of the IPM Documentation.

TABLE 8—HG EMISSIONS AND CONTROL PERFORMANCE OF LIGNITE-FIRED EGUS IN 2021—Continued

Plant name	Hg inlet (lb/TBtu)	Est Hg control at 4.0 lb/TBtu (%)	Est Hg control at 1.2 lb/TBtu (%)	Est 2021 Hg inlet (lb/TBtu)	2021 Hg outlet (lb/TBtu)	Est 2021 Hg control (%)	Est 2021 Hg control at 1.2 lb/TBtu (%)
Oak Grove #1	14.88	73.1	91.9	14.60	2.01	86.2	91.8
Oak Grove #2	14.88	73.1	91.9	14.88	2.59	82.6	91.9
Red Hills #1	12.44	67.8	90.4	12.40	1.33	89.3	90.3
Red Hills #2	12.44	67.8	90.4	12.40	1.35	89.1	90.3
San Miguel	14.65	72.7	91.8	14.62	2.81	80.8	91.8

As can be seen in the table, all lignite-fired EGUs are estimated to meet the current standard by achieving a level of control of less than 75 percent. The average reported 2021 Hg emission rate for lignite-fired EGUs located in North Dakota was 3.0 lb Hg/TBtu with an average control of 83.7 percent. The average reported 2021 Hg emission rate for lignite-fired EGUs located in Texas and Mississippi was 2.0 lb Hg/TBtu (with an average control of 88.2 percent).

f. Proposed Revision of the Hg Emission Standard for Lignite-Fired EGUs

Several commenters have provided information on new developments in Hg control technology. One commenter [38] indicated that improvements in halogen and ACI technologies have significantly lowered the costs of those pollution control systems. The use of computational fluid dynamics and physical modeling has also improved pollutant capture and reduced sorbent consumption. The commenter further noted that ACI systems operate more reliably, and many users utilize technology to improve the dispersion of sorbents in flue gas for better performance. After reviewing the available literature and other studies and available information, the assumptions made regarding Hg control in the 2012 MATS Final Rule, and the information obtained from compliance reports and the 2022 CAA section 114 information collection, the EPA has determined that there are developments in practices, processes, and control technologies since 2012 that warrant consideration of revising the Hg standards for lignite-fired EGUs. As explained below, the EPA has further determined that available controls and methods of operation that will allow lignite-fired EGUs to meet the same Hg emission standard that is being met by EGUs firing on non-lignite coals, and that the costs of doing so are reasonable.[39] Therefore, the EPA is proposing to revise the Hg emission standard for lignite-fired EGUs to 1.2E–06 lb/MMBtu.

i. Both Lignite and Subbituminous Coal Are Low Rank Coals With Low Halogen Content

Coal is classified into four main types, or ranks: [40] anthracite, bituminous, subbituminous, and lignite. The ranking depends on heating value of the coal. Anthracite has the highest heating value of all ranks of coal and is mostly used by the metals industry (it is rarely using for power production). Anthracite accounted for less than 1 percent of the coal mined in the U.S. in 2021. Bituminous coal is also considered a ''high rank coal'' because of its higher heating value. It is the most abundant rank of domestic coal and accounted for about 45 percent of total U.S. coal production in 2021. Bituminous coal is used to generate electricity and in other industries.

Subbituminous coal and lignite are referred to as ''low rank coals.'' They both have lower heating values than bituminous coal. Subbituminous coal accounted for about 46 percent of total U.S. coal production in 2021, with the vast majority produced in the Powder River Basin (PRB) of Wyoming and Montana. Lignite has the lowest energy content of all coal ranks. Lignite accounted for about 8 percent of total U.S. coal production in 2021.[41] About 56 percent was mined in North Dakota (Fort Union lignite) and about 36 percent was mined in Texas (Gulf Coast lignite).

Chlorine is the most abundant halogen in coal. Bromine may also be present in coal but is typically in much lower concentrations than chlorine.[42] Low-rank coals such as lignite and subbituminous generally have lower chlorine contents than higher rank coals such as bituminous coal.[43]

As mentioned earlier, the halogen content of the coal—especially chlorine—largely influences the oxidation state of Hg in the flue gas stream. As a result, the halogen content of the coal directly influences the ability to capture and contain the Hg before it is emitted into the atmosphere. As explained earlier, ash from lignite and subbituminous coals tends to be more alkaline (relative to that from bituminous coal) due to the lower amounts of sulfur and halogen and the presence of a more alkaline and reactive (non-glassy) form of calcium in the ash. The natural alkalinity of the subbituminous and lignite fly ash can effectively neutralize the limited free halogen in the flue gas and prevent oxidation of the Hg^0. This makes control of Hg from both subbituminous coal-fired EGUs and lignite-fired EGUs more challenging than the control of Hg from bituminous coal-fired EGUs. However, because control strategies and technologies were developed to introduce halogens to the flue gas stream, EGUs firing subbituminous coals have been able to meet the 1.2 lb/TBtu emission standard in the 2012 MATS Final Rule. As mentioned earlier, EGUs firing subbituminous coal in 2021 emitted Hg at an average annual rate of 0.6 lb Hg/TBtu with measured values as low as 0.1 lb/TBtu. Clearly EGUs firing subbituminous coal have found control options to meet—and exceed—the 1.2 lb/TBtu emission standard despite the challenges presented by the low natural halogen content of the coal and production of difficult-to-control elemental Hg vapor in the flue gas stream.

[38] See EPA–HQ–OAR–2018–0794–1171.

[39] As discussed in section V.B above, prior CAA section 112(d)(2) technology reviews conducted by the EPA establish that obtaining better information on performance of controls can provide the basis for updates to standards under a technology review.

[40] ''Coal Explained, Types of Coal'' Energy Information Administration, available at *www.eia.gov/energyexplained/coal* and in the rulemaking docket.

[41] EIA Annual Coal Report 2021, October 2022, *https://www.eia.gov/coal/annual/pdf/acr.pdf.*

[42] See Figure 5 in the U.S. Geological Survey publication ''Mercury and Halogens in Coal—Their Role in Determining Mercury Emissions From Coal Combustion'' available at *https://pubs.usgs.gov/fs/2012/3122/pdf/FS2012-3122_Web.pdf.*

[43] *Id.*

ii. The Hg Content of Fort Union Lignite and PRB Subbituminous Coal Are Similar

As can be seen in Table 8 above, for the 2012 MATS Final Rule, the EPA estimated the Fort Union lignite-fired EGUs inlet Hg concentration at up to 7.8 lb/TBtu and estimated the inlet Hg concentration of subbituminous coal-fired EGUs at up to 8.65 lb/TBtu. These values are very similar to results from a published study that found the average Hg concentration of Fort Union lignite and PRB subbituminous coals to be very similar. The study found that the Fort Union lignite samples contained an average of 8.5 lb/TBtu and the PRB subbituminous coal samples contained an average of 7.5 lb/TBtu.[44] Despite the similarities in Hg content, halogen content, and alkalinity between Fort Union lignite and PRB subbituminous coal, EGUs firing subbituminous coal in 2021 emitted Hg at an average annual rate of 0.6 lb Hg/TBtu while those firing on Fort Union lignite emitted Hg at an average annual rate of 3.0 lb Hg/TBtu. While the EGUs firing Fort Union lignite at an average emission rate of 3.0 lb Hg/TBtu are complying with the 2012 MATS Final Rule emission standard of 4.0 lb Hg/TBtu, it is difficult to justify why those units should not meet a similar level of Hg control as that of the EGUs firing PRB subbituminous coal given the similarities between the two fuels—especially the similarities in Hg content, halogen content, and alkalinity.

iii. The Hg Content of Gulf Coast Lignite Is Greater Than That of Fort Union Lignite; and Several Lignite-Fired EGUs in Texas Have Co-Fired Significant Quantities of Subbituminous Coal

The Hg content of Gulf Coast lignite tends to be higher than that of the Fort Union lignite. As can be seen in Table 8 above, for the 2012 MATS Final Rule, the EPA estimated the inlet Hg concentration for Gulf Coast lignite-fired EGUs at an average inlet Hg concentration of up to 14.9 lb/TBtu (as compared to average inlet Hg concentrations of up to 7.8 lb/TBtu for Fort Union lignite). Despite the higher Hg content in Gulf Coast lignite, EGUs permitted as lignite-fired had, in 2021, an average Hg emission rate of 2.0 lb/TBtu—which was lower than the 2021 average emission rate of EGUs firing Fort Union lignite (at 3.0 lb/TBtu). This is due, in part, because some EGUs in Texas that are permitted as lignite-fired units (and thus subject to the Hg emission standard of 4.0 lb/TBtu) were, in 2021, firing significant amounts of subbituminous coal. Firing high levels of non-lignite coal (in some cases greater than 99 percent non-lignite coal), while remaining subject to the less stringent Hg emission standard for the subcategory of lignite-fired EGUs seems to fit the scenario that the EPA expressed concern about in the 2012 MATS Final Rule preamble—that ''sources to potentially meet the definition by combusting very small amounts of low rank virgin coal [lignite].'' See 77 FR 9379.

iv. The Proposed More Stringent Hg Emission Standard Can Be Achieved, Cost-Effectively, Using Available Control Technology

For the 2012 MATS Final Rule, the EPA calculated beyond-the-floor costs for Hg controls by assuming injection of brominated activated carbon at a rate of 3.0 lb/MMacf for units with ESPs and injection rates of 2.0 lb/MMacf for units with baghouses (also known as FF). Yet, in responses to the CAA section 114 information survey, only one facility (Oak Grove) explicitly indicated use of brominated activated carbon. Oak Grove units #1 and #2 (both using FF for PM control) reported use of brominated activated carbon at an average injection rate of less than 0.5 lb/MMacf for operation at capacity factor greater than 70 percent. The Oak Grove units fired, in 2021, using mostly refined coal.[45] That injection rate is considerably less than the 2.0 lb/MMacf assumed.

From the CAA 114 information survey, the average injection rate reported for non-halogenated sorbents was 2.5 lb/MMacf. The average sorbent injection rate ranged from 10–65 percent of the maximum design sorbent injection rate (the average was 36 percent of the maximum design rate). As mentioned earlier, most sources utilized a control strategy of sorbent injection coupled with chemical (usually halogenated) additives. In the beyond-the-floor analysis in the 2012 MATS Final Rule, we noted that the results from various demonstration projects suggests that greater than 90 percent Hg control can be achieved at lignite-fired units using brominated activated carbon sorbent at an injection rate of 2.0 lb/MMacf for units with installed FFs for PM control and at an injection rate of 3.0 lb/MMacf for units with installed ESPs for PM control. As shown in Table 8 above, all units (in 2021) would have needed to control their Hg emissions to less than 92 percent to meet an emission standard of 1.2 lb/TBtu. Based on this, we expect that the units could meet the proposed, more stringent, emission standard of 1.2 lb/TBtu by utilizing brominated activated carbon at the injection rates suggested in the beyond-the-floor memo[46] from the 2012 MATS Final Rule.

To determine the cost-effectiveness of that strategy, we calculated the incremental cost-effectiveness (cost per lb of Hg controlled) for a model 800 MW lignite-fired EGU. We calculated the incremental cost of injecting non-brominated activated carbon sorbent at a sufficiently large injection rate of 5.0 lb/MMacf to achieve an emission rate of 1.2 lb/TBtu versus the cost to meet an emission rate of 4.0 lb/TBtu using non-brominated activated carbon sorbent at an emission rate of 2.5 lb/MMacf. For an 800 MW lignite-fired EGU, the incremental cost effectiveness was $8,703 per incremental lb of Hg removed. The actual cost-effectiveness is likely lower than this value as it is unlikely that sources will need to inject brominated activated carbon sorbent at rates as high as 5.0 lb/MMacf (the Oak Grove units were injecting less than 0.5 lb/MMacf) and is well below the cost that the EPA has found to be acceptable in previous rulemakings (*e.g.,* $27,500/lb Hg was proposed to be cost-effective for the Primary Copper RTR (87 FR 1616); approximately $27,000/lb Hg was found to be cost-effective in the beyond-the-floor analysis supporting the 2012 MATS Final Rule[47]).

In summary, the EPA is proposing to revise the Hg emission standard for lignite-fired EGUs from 4.0E–06 lb/MMBtu to 1.2E–06 lb/MMBtu, which is the same Hg emission limit that non-lignite-fired EGUs must meet. We are proposing to revise this emission standard while recognizing that Hg from the combustion of lignite is challenging to capture because of the lack of naturally occurring halogen in the fuel and because of the natural alkalinity of the resulting fly ash. However, Hg from the combustion of subbituminous coal is similarly challenging to capture for the same reasons. Yet, EGUs firing subbituminous coal in 2021 emitted Hg at an average rate of 0.6 lb/TBtu and some as low as 0.1 lb/TBtu. From the CAA section 114 information survey, very few lignite-fired EGUs are using the control technology that the EPA identified as the most effective for Hg control in the 2012 MATS Final Rule,

[44] ''Mercury in North Dakota lignite'', Katrinak, K.A.; Benson, S.A.; Henke, K.R.; Hassett, D.J.; *Fuel Processing Technology,* 39, 35, 1994.

[45] EIA form 923 does not specify the rank of coal that is ''refined'' in boiler or generator fuel data. For this technology review, the EPA has assumed that facilities reporting the use of refined coal have utilized ''refined lignite,'' which was confirmed in EIA form 923 fuel receipts and costs.

[46] See Docket ID No. EPA–HQ–OAR–2009–0234–20130 at *regulations.gov.*

[47] *Ibid.*

brominated ACI, which many demonstration projects have shown can achieve Hg control of greater than 90 percent. Although we are not proposing to mandate the use of any particular control technology, we have shown that use of brominated activated carbon sorbent injection can be used to cost-effectively meet the more stringent emission.

We also considered the energy implications and non-air environmental impacts of this proposed revision of the Hg emission standard for lignite-fired EGUs. We do not anticipate any energy implications from this proposed revision as most units are already using sorbent injection technology as part of the Hg control strategy and we do not project significant changes in unit operations as a result of the proposed revision. Regarding the non-air environmental impact, we anticipate that there may be positive non-air environmental impacts. The current strategies employed by most lignite-fired EGUs involve the injection of oxidizing halogen additives and, separately, injection of sorbent (typically non-brominated activated carbon). Because homogeneous (gas-phase) oxidation of Hg^0 is kinetically limited, most of the Hg^0 oxidation is thought to occur as heterogeneous (solid-phase) reactions resulting from halogens or other oxidants attached to flue gas solids (*e.g.,* unburned carbon, other). This is essentially a two-step process where the injected (or natural) halogen (chloride or bromide) must first attach to a flue gas solid and then contact and react with gas-phase Hg^0. The addition of sorbent that has already been pre-halogenated (most often brominated) is more efficient as the first step occurs prior to injection. This means that less bromine will be unutilized and captured in a downstream control device or potentially included in the plant water effluent discharge. The EPA requests comment on its expectation that most EGUs (including lignite-fired EGUs) will no longer use ''refined coal'' due to the expiration of the refined coal tax credit. The amount of Br on brominated activated carbon is much less than that used to produce refine coal, and Br is retained on the activated carbon sorbent where it reacts with gas phase Hg and is captured by downstream control devices. Thus, the EPA believes that cross-media transfers of bromine to receiving waterbodies and emitted to the atmosphere, especially when wet FGD is not employed, are not expected (or would certainly be lower) with the use of brominated sorbents as compared to use of refined coal and that any negative health, ecological, and productivity effects associated with bromine transfer to water effluent will be minimized or avoided, especially given the EPA's proposed zero-discharge requirements under the Clean Water Act (88 FR 18824; March 29, 2023).

4. No Revisions to Work Practice Standards for Organic HAP

Following promulgation of the 2020 Final Action, in which the EPA found no developments in new technology or methods of operation that would result in cost-effective emission reductions of organic HAP and thus did not revise the work practice standards for organic HAP, the EPA received a petition for reconsideration that, in relevant part, requested the EPA to reconsider work practice standards for organic HAP.[48] Our review of new technology and of methods of operation conducted as part of this technology review proposal also found no developments that would result in cost-effective emission reductions of organic HAP. Likewise, we are not proposing revisions to the organic HAP work practice standards finalized in the 2012 MATS Final Rule.[49] The EPA acknowledges that it received a petition for reconsideration from environmental organizations that, in relevant part, sought the EPA's reconsideration of organic HAP work practice standards, which the EPA continues to review and will respond to in a separate action.[50]

5. No Proposed Revisions to the Acid Gas Standards for Coal-Fired EGUs

The EPA evaluated the use of control technologies and strategies that are commonly used for control of acid gas HAP (*e.g.,* HCl, HF). These control technologies and strategies include the use of wet FGD scrubbers, spray drier absorber (SDA) scrubbers, reagent injection (for fluidized combustors), dry sorbent injection (DSI), and use of low sulfur or low halogen fuels. As described in section III of this preamble, EGUs in six subcategories are subject to numeric emission limits for acid gas HAP (*e.g.,* HCl, HF). Emission standards for HCl serve as a surrogate for all acid gas HAP, with an alternate standard for SO_2 that may be used as a surrogate for the acid gas HAP at coal-fired EGUs with operational FGD systems and SO_2 CEMS.

[48] See Docket ID No. EPA–HQ–OAR–2018–0794–4565 at *www.regulations.gov.*

[49] See 40 CFR 63.9991, Table 3.

[50] See Docket ID No. EPA–HQ–OAR–2018–0794–4565 at *www.regulations.gov.*

When the EPA finalized the 2012 MATS Final Rule, the primary air pollution control devices installed at EGUs for the control of acid gases were wet scrubbers (wet FGD), dry scrubbers (dry FGD or spray dryer absorber, SDA), and reagent injection (at fluidized bed combustors). These technologies are still in wide use for acid gas HAP control. An additional acid gas control technology—dry sorbent injection (DSI)—was in limited use in the power sector at the time the MATS rule was finalized but has seen increased use since (approximately 20 percent of EGUs operating in 2021 utilized DSI for acid gas control for one reason or another).

A wet FGD scrubber uses an alkaline liquid slurry (usually a limestone or lime slurry) to remove acidic gases from an exhaust stream. The acid gases react with the alkaline compounds in the slurry and are removed as scrubber solids (*e.g.,* $CaSO_3$ or $CaSO_4$) or may be captured due to their solubility in the scrubber slurry. Most wet FGD scrubbers have SO_2 removal efficiencies exceeding 90 percent and perform even better for HCl and HF. Dry FGD scrubbers (SDA) are an acid gas pollution control system where an alkaline sorbent slurry is injected into the flue gas stream to react with and neutralize acid gases in the exhaust stream forming a dry powder material which is then captured in a downstream PM control device (usually an FF). Alkaline sorbent injection systems (reagent injection) are also used in fluidized bed combustors (FBC) and circulating fluidized bed (CFB) boilers for control of acid gases. In that use, the alkaline sorbent (usually powdered limestone) is injected into the combustion chamber with the primary fuel. Dry sorbent injection (DSI) is an add-on air pollution control system in which a dry alkaline powdered sorbent (typically sodium- or calcium-based) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device. The EPA evaluated the use of these control technologies (wet FGD scrubbers, SDA, reagent injection, and DSI), and the strategic use of low sulfur or low halogen fuels.

The EPA reviewed compliance data for SO_2 and/or HCl, as shown in Figure 3 of the Technical Memo, showing EGUs with highest SO_2 emissions in 2021 to those with the lowest SO_2 emissions in 2021. Approximately two-thirds of coal-fired EGUs have demonstrated compliance with the alternative SO_2 emission standard rather than the HCl emission limit. About one-third of EGUs have demonstrated compliance with the primary acid gas emission limit for HCl. And some sources have reported emissions data that demonstrates compliance with either of the standards. The emission rates for HCl that are shown in Figure 3 of the Technical Memo distinguish between EGUs that utilize some sort of acid gas control system—which would be a wet FGD scrubber, a dry scrubber (an SDA), reagent injection or DSI—and EGUs that do not have a wet FGD scrubber or an SDA and do not utilize either reagent injection or DSI. All of the EGUs with no acid gas controls are units that were firing subbituminous coal and were likely able to demonstrate compliance with the HCl emission standard due to the low natural chlorine content and high alkalinity of most subbituminous coals.

All sources submit SO_2 emissions data to comply with other CAA requirements (*e.g.,* the Acid Rain Program). As mentioned earlier, some sources submitted emissions data that demonstrates compliance with either the HCl standard or the alternative SO_2 standard. The average SO_2 emission rate for units at or below the alternative SO_2 emission limit was 9.0E–02 lb SO_2/MMBtu, which is approximately 55 percent below the SO_2 emission limit of 2.0E–01 lb SO_2/MMBtu. The average HCl emission rate for units demonstrating compliance with the SO_2 standard but also reporting HCl emissions was 4.0E–04 lb HCl/MMBtu, which is approximately 80 percent below the HCl emission limit of 2.0E–03 lb HCl/MMBtu. This result is consistent with the EPA's rationale for establishing the alternative SO_2 emission limit—because HCl emissions are much more easily controlled than SO_2 emissions (HCl and HF are much more reactive and much more water soluble than SO_2), controlling emissions of SO_2 using FGD controls very effectively controls emissions of HCl. Note that an EGU may demonstrate compliance with the acid gas surrogate SO_2 standard only if the unit has some type of installed acid gas control and an operational SO_2 CEMS.

The EPA looked further at the HCl emissions of the EGUs operating in 2021 with and without acid gas controls. The average emission rate of EGUs with no add-on acid gas control was 8.0E–04 lb HCl/MMBtu, which is 60 percent below the SO_2 emission limit.

The EPA looked closer at the relative performance of acid gas controls for HCl emissions. The best performing EGUs tend to be those that utilize either wet or dry FGD scrubbers, with units utilizing sorbent injection emitting at slightly higher rates. The units that utilize DSI with an FF tend to have lower HCl emissions than those that utilize DSI with an ESP. This is an expected outcome as the filter cake on the FF provides great opportunity for contact with the gas phase acid gases.

Overall, the EPA has evaluated acid gas emissions data from MATS-affected EGUs and have determined that some units have demonstrated compliance with the primary HCl emission standard using acid gas control technologies (wet FGD scrubbers, SDA, reagent injection, and DSI) and through the strategic use of low-halogen, high-alkalinity fuels. Other units have demonstrated compliance with acid gas emission limits by meeting or exceeding the alternative surrogate SO_2 emission standard. The average HCl emission rates for units with add-on acid gas controls was 4.0E–04 lb HCl/MMBtu which is approximately 80 percent below the MATS HCl emission limit. The average HCl emission rates for units with no add-on acid gas controls was 8.0E–04 lb HCl/MMBtu (approximately 60 percent below the MATS HCl emission limit). It is not clear that improvements in a wet or dry FGD scrubber would result in additional HCl emission reductions since HCl emissions are already much easier to control than SO_2 emissions. The EPA does not have information on the sorbent injection rates for DSI systems; so, we cannot assess whether increased sorbent injection would result in additional HCl emission reductions. Units using DSI in combination with an ESP would almost certainly see improved performance if they were to replace the ESP with a FF. However, that small incremental reduction in HCl emissions would come at a high cost and would certainly not be a cost-effective option.

In the 2020 Technology Review, the EPA concluded that ''the existing acid gas pollution control technologies that are currently in use are well-established and provide the capture efficiencies necessary for compliance with the promulgated MATS rule limits.'' Comments received during the 2020 Proposal did not provide any new practices, processes, or control technologies for acid gas control. One commenter noted that ''in the short time since the RTR was finalized, there have been no developments in practices, processes, or control technologies, nor any new technologies or practices for the control of . . . acid gas HAP'' (Docket ID No. EPA–HQ–OAR–2018–5121). Another commenter pointed to an independent comprehensive report to show acid gas emission controls had better performance and lower capital costs than the EPA assumed in the 2011 modeling (Docket ID No. EPA–HQ–OAR–2018–0794–4962). That report suggested control technology improvements to acid gas controls to achieve revised HCl emission standards of 1.0E–03 lb HCl/MMBtu, 6.0E–04 lb HCl/MMBtu, and 1.0E–05 lb HCl/MMBtu through addition of new DSI systems, upgrades to existing DSI systems, upgrades to existing wet and dry scrubbers, and, for the most stringent options, installation of new FFs. However, as mentioned earlier—and as detailed further in the Technical Memo—it is not clear that such improvements targeting acid gases would result in corresponding reductions in HCl or HF emissions, as emissions of HCl and HF are already much easier to control than emissions of SO_2.

In summary, the EPA has not identified any new control technologies or any improvements to existing acid gas controls that would result in additional cost-effective acid gas HAP emission reductions from coal-fired EGUs and is, therefore, not proposing revisions to the acid gas emission standards or for the surrogate SO_2 emission standard. However, the EPA solicits comment on any new practices, processes, or technologies for control of acid gas HAP emissions, including any information on whether increased sorbent injection rates (for sources using DSI or SDA controls) would result in additional HCl emission reductions, that could inform the potential for additional cost-effective acid gas HAP emission reductions from coal-fired EGUs.

6. No Proposed Revisions to Standards for Continental Liquid Oil-Fired EGUs

The annual capacity factors of most continental liquid oil-fired units are low. Based on available data reported to the EIA and the EPA's Clean Air Markets Program Data (CAMPD), in 2021 the average annual capacity factor for liquid oil-fired units was 3 percent. Additionally, there were only two continental liquid oil-fired units identified with 2-year capacity factors greater than 8 percent. Those two units primarily fire natural gas but had heat input-based percentages of fuel oil firing that were about 16 percent in at least one of the years from 2019 through 2021 (*i.e.,* slightly above the 15 percent that would qualify them as oil-fired units). Therefore, it is likely that there are very few continental liquid oil-fired units that would be outside of the definition of the limited-use liquid oil-fired subcategory.

Furthermore, for the continental liquid oil-fired units with available data that are likely limited-use units, the cumulative percentage of heat input from residual fuel oil in 2021 was 32 percent, the heat input of distillate fuel oil was 4 percent, and the heat input from natural gas was 64 percent. Because the capacity factors of most continental liquid oil-fired units are low, and most combustion by those units is using fuel (*i.e.,* natural gas) with low metallic HAP emission rates, the EPA is not proposing changes to the total HAP metals (which includes Hg), nor to the standards for the individual HAP metals, nor to the HAP metal surrogate fPM emission standard for continental liquid oil-fired electricity generating units.

However, given there have been several recent temporary and localized increases in oil combustion at continental liquid oil-fired EGUs during periods of extreme weather conditions, such as the 2023 polar vortex in New England, the EPA seeks comment on whether the current definition of the limited-use liquid oil-fired subcategory remains appropriate or if, given the increased reliance on oil-fired generation during periods of extreme weather, a period other than the current 24-month period or a different threshold would be more appropriate for the current definition. The EPA also seeks comment on the appropriateness of including new HAP standards for EGUs subject to the limited use liquid oil-fired subcategory, as well as on the means of demonstrating compliance with the new HAP standards. For example, in order to reduce HAP emissions during periods of extreme weather conditions, it may be appropriate for limited-use liquid oil-fired EGUs to use distillate fuel oil instead of residual oil, or to switch from residual oil to cleaner fuels after a certain number of hours of operation, or to be subject to an annual or seasonal limit of residual oil firing. The EPA solicits comment on each of these options.

The EPA also solicits comment on establishing a HAP emission limit on liquid oil-fired EGUs (including those in the limited-use subcategory and those located in non-continental areas) where compliance would be demonstrated through fuel sampling and analysis. The EPA seeks comment from the regulated community, citizens, and regulatory authorities on the need for a revision to the limited-use oil-fired subcategory definition and on additional, cost-effective methods to minimize HAP emissions during periods of limited operation.

7. No Proposed Revisions to Standards for Non-Continental Liquid Oil-Fired EGUs

Hawaiian Electric Company (HECO) operates 12 liquid oil-fired boilers at its Waiau Generating Station (Pearl City, HI) and at its Kahe Generating Station (Kapolei, HI). Their average capacity factor in 2021 was 29.6 percent (on a net basis) and they fire on residual fuel oil. HECO has, in compliance reports, reported fPM emission rates to the EPA that are below the fPM emission rate of 3.0E–02 lb/MMBtu.

In Puerto Rico, there are 14 liquid oil-fired MATS-affected EGUs (3,552 MW total capacity) at four separate facilities operated by the Puerto Rico Electric Power Authority (PREPA). The EGUs operate using residual fuel oil and do not currently have any emission controls for NO_X, PM or SO_2. At least two of the units have dual fuel capabilities and have operated on high levels of natural gas. There is limited stack testing data available, but testing done in 2021 and 2022 indicated fPM emission rates ranging from 2.6E–02 lb/MMBtu to 2.9E–02 lb/MMBtu, a range that is just below the fPM emission rate of 3.0E–02 lb/MMBtu.

As mentioned earlier in section IV.A of this preamble summarizing the 2020 Residual Risk Review, the results of the chronic inhalation cancer risk assessment based on actual emissions indicated that the estimated maximum individual lifetime cancer risk (cancer MIR) was 9-in-1 million, with nickel emissions from oil-fired EGUs at these four facilities in Puerto Rico as the major contributor to the risk. The total estimated cancer incidence from this source category was 0.04 excess cancer cases per year, or one excess case in every 25 years. Approximately 193,000 people were estimated to have cancer risks at or above 1-in-1 million from HAP emitted from the facilities in this source category. The estimated maximum chronic noncancer TOSHI for the source category was 0.2 (respiratory), which was driven by emissions of nickel and cobalt from the oil-fired EGUs.

Since these oil-fired EGUs do not have installed control devices for HAP metals (PM controls), there is no opportunity to improve their performance in the same ways the EPA found available to some coal-fired EGUs. PREPA has recently proposed near-term retirement dates (by 2026) for 10 of the 14 oil-fired EGUs with two of the other four remaining boilers burning mostly natural gas.

Because of the low capacity factors of the Hawaii oil-fired EGUs and the near-term retirement dates of most of the Puerto Rico liquid oil-fired EGUs and plans for a transition to greater use of natural gas for the remaining boilers, the EPA is not proposing to revise emission standards for non-continental oil-fired EGUs.

However, the EPA seeks comment on whether the fPM surrogate emission standard is appropriate for these non-continental liquid oil-fired EGUs. As mentioned, the largest risks identified in the 2020 RTR were associated with nickel emissions from residual oil-fired EGUs located in Puerto Rico. The EPA solicits comment on eliminating or revising the fPM standard for existing non-continental sources, and, instead, requiring these EGUs to comply with the existing emission limits for the individual metals, including nickel. In addition, the EPA also seeks comment on the appropriateness of including new HAP standards for EGUs in Puerto Rico and Hawaii, as well as other non-continental U.S. areas, such as Guam and the Virgin Islands, and the means of demonstrating compliance with the new HAP standards. For example, the EPA seeks input on whether, in order to reduce HAP emissions and associated risks in these places, oil-fired EGUs should be required to switch from residual oil to cleaner fuels, or to switch to cleaner fuels after a certain number of hours of operation, or should be subject to an annual limit of residual oil firing. The EPA solicits comment on whether compliance with a HAP metal emission limit could be demonstrated by fuel sampling and analysis. The EPA solicits comment on the need for additional, cost-effective methods to minimize HAP emissions in non-continental states and territories—including Hawaii, Puerto Rico, the U.S. Virgin Islands, and Guam. We solicit comment on any special considerations—including the availability of clean fuels such as distillate fuel oil and natural gas—in non-continental areas.

8. No Proposed Revisions to Standards for IGCC EGUs

The EPA is aware of two existing IGCC facilities that meet the definition of an IGCC EGU. The Edwardsport Power Station, located in Knox County, Indiana, includes two IGCC EGUs that had 2021 average capacity factors of approximately 85 percent and 67 percent. The Polk Power Station, located in Polk County, Florida, had a 2021 average capacity factor of approximately 70 percent, but burned only natural gas in 2021.

While this subcategory has a less stringent fPM standard of 4.0E–02 lb/MMBtu (as compared to that of coal-fired EGUs), recent compliance data indicates fPM emissions well below the most stringent standard option of 6.0E–03 lb/MMBtu that was evaluated for coal-fired EGUs. Since there are only two IGCC EGU facilities, and the EPA is unaware of any developments in the HAP emission controls used at IGCC units, the EPA is not proposing to revise any of the emission standards for this subcategory. However, the EPA is proposing that the affected facilities must install a PM CEMS to demonstrate compliance with the existing fPM limit. Further, the EPA solicits comment on cost-effective methods to achieve additional HAP emission reductions from this subcategory.

D. What other actions are we proposing, and what is the rationale for those actions?

In addition to the proposed actions described above, we are proposing additional revisions to the NESHAP.

1. Startup Requirements

In the Reconsideration of Certain Startup/Shutdown Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional and Small Industrial-Commercial-Institutional Steam Generating Units (79 FR 68777; November 19, 2014), the EPA took final action on its reconsideration of the startup and shutdown provisions by adding an alternative work practice standard for startup periods. That alternative work practice standard, referred to as paragraph (2) of the definition of ''startup'', required clean fuel use to the maximum extent possible, operation of PM control devices within 1 hour of introduction of primary fuel (*i.e.,* coal, residual oil, or solid oil-derived fuel) to the EGU, collection and submission of records of clean fuel use and emissions control device capabilities and operation, as well as adherence to applicable numerical standards within 4 hours of the generation of electricity or thermal energy for use either on site or for sale over the grid (*i.e.,* the end of startup) and to continue to maximize clean fuel use throughout that period. The EPA provided this alternative work practice because many commenters asserted it would be difficult, if not impossible, for their EGUs to meet the already-promulgated startup work practices.[51] In *Chesapeake Climate Action Network* v. *EPA,* the D.C. Circuit remanded the alternative work practice standard for startup and shutdown to the EPA for reconsideration based on a petition for reconsideration from environmental groups. 952 F.3d 310 (D.C. Cir. 2020). In this action, and in conjunction with the EPA's authority pursuant to CAA section 112(d)(6), the EPA is granting in part petitions for reconsideration which sought the EPA's review of startup and shutdown provisions.[52] As part of our obligation to address the remand on this issue, we reviewed the information available to us. As discussed below, that information shows that the conditions contained in the alternative work practice standard do not represent what the best performers are able to do; moreover, as a practical matter, few EGUs have chosen to use the alternative work practice standard.

The EPA was able to identify 14 EGUs with the ability to generate up to 8.4 GW that chose to use the alternative work practice for startup periods. As shown in Table 9 below, six of those EGUs with the ability to generate up to 3.2 GW have retired and one of those EGUs with the ability to generate up to 0.7 GW will retire by 2025.

TABLE 9—EGUS RELYING ON PARAGRAPH (2) OF THE DEFINITION OF ''STARTUP''

EGU name	Unit	ORIS code	MW	Notes	Fuel
Prairie State Generating	1	55856	877		Bituminous.
Prairie State Generating	2	55856	877		Bituminous.
Brame Energy Center	Rodemacher 2	6190	552		Subbituminous.
Brame Energy Center	Madison 3–1	6190	600		Petroleum coke, coal.
Brame Energy Center	Madison 3–2	6190	600		Petroleum coke, coal.
Dolet Hills	1	51	720	Retired 2021	Lignite.
Sherburne	3	6090	938.7	Retires 2034	Subbituminous.
Westwood	1	50611	36		Waste coal.
Centralia	BW21	3845	729.9	Retired 2020	Subbituminous.
Centralia	BW22	3845	729.9	Retires 2025	Subbituminous.
St Johns River	1	207	679	Retired 2018	Bituminous.
St Johns River	2	207	679	Retired 2018	Bituminous.
HMP&L Station 2	H1	1382	200	Retired 2019	Bituminous.
HMP&L Station 2	H2	1382	200	Retired 2019	Bituminous.

After the planned retirements in 2025, just seven EGUs with the ability to generate up to 4.5 GW will remain; this represents less than 0.4 percent of electrical generation from all affected sources and less than 1.7 percent of the 278 GW of coal-fired and other, non-natural gas fossil-fired electrical generation available in 2022. We solicit comment on whether we have identified all of the EGUs relying on paragraph (2) of the definition of ''startup'', as well as their associated retirement dates as reported to the Department of Energy's EIA. Commenters, particularly owners or operators of affected EGUs, should provide us with corrected information as, or if, necessary. Despite comments from EGU owners or operators and their industry representatives opposing use of paragraph (1) of the definition of ''startup'', the owners or operators of coal- and oil-fired EGUs that generated over 98 percent of electricity in 2022 have made the requisite adjustments, whether through greater clean fuel capacity, better tuned equipment, better trained staff, a more efficient or better design structure, or a combination of factors, to be able to meet the requirements of paragraph (1) of the definition of ''startup.''

[51] See *Assessment of Startup Period at Coal-Fired Electric Generating Units,* available at Docket ID No. EPA–HQ–OAR–2009–0234–20378.

[52] See Docket ID No. EPA–HQ–OAR–2018–0794–4565 at *www.regulations.gov; see also Chesapeake Climate Action Network* v. *EPA,* 952 F.3d 310 (D.C. Cir. 2020).

Consistent with the MACT emission standard setting requirement for using the average of the best performing 12 percent of sources to establish emission standards, we propose to remove the alternative work practice standards, *i.e.,* those contained in paragraph (2) of the definition of ''startup'', from the rule. As demonstrated by the majority of EGUs currently relying on the work practice standards in paragraph (1) of the definition of ''startup'', we believe such a change is achievable by all EGUs; further, we expect such a change would result in little to no additional expenditure since the additional recordkeeping and reporting provisions associated with the work practice standards of paragraph (2) of the definition of ''startup'' were more expensive than the requirements of paragraph (1) of the definition of ''startup.'' We solicit comment on our proposal to remove the work practice standards of paragraph (2) of the definition of ''startup.''

2. Removing Non-Hg Metals Limits

The current MATS rule contains individual and total non-Hg metals emissions limits, as well as fPM emission limits. Those fPM emission limits serve as alternative emission limits because fPM was found to be a surrogate for either individual or total non-Hg metals emissions. As explained and used above to quantify individual and total non-Hg metals reductions from our proposed fPM emission limit revision, the relationship between individual and total non-Hg metals and fPM was determined by EGU fuel type and control device using data collected by the 2010 ICR.[53] While EGU owners or operators have the ability to use individual or total non-Hg metals emissions as the compliance method for the 358 EGUs when this action takes effect and with generation of at least 25 MW,[54] we are aware of just one owner or operator who provides non-Hg metals data—both individual and total—along with fPM data for compliance purposes for one waste coal-fired EGU with generating capacity of 46.1 MW. Given that owners or operators of the other EGUs applicable to MATS have chosen to demonstrate compliance with only the fPM emission limit, we propose to remove the non-Hg metals emission limits—both individual and total—from MATS. Removal of the non-Hg metals emission limits renders the LEE option for non-Hg metals (individual and total) obsolete and the EPA is proposing to remove those standards as well. Removal of the non-Hg metals emissions limits simplifies the compliance determination path for EGU owners or operators and reduces the amount of regulatory text, making the rule clearer yet continuing to ensure that non-Hg metals emissions remain below limits on an ongoing basis, particularly when the fPM is measured as proposed with PM CEMS, given that non-Hg metals emissions provided for one EGU are obtained via quarterly stack testing. We solicit comment on the number of EGUs that currently rely on non-Hg metals emissions measurement for MATS compliance purposes; to the extent that other EGU owners or operators rely on non-Hg metals emissions for compliance purposes, please be sure to identify each EGU, its nameplate generating capacity, its anticipated or announced retirement date (if applicable), and its Office of Regulatory Information Systems (ORIS) Code. We solicit comment on our proposal to remove the non-Hg metals emission limits from all existing MATS-affected EGUs.

If we were to change our position by deciding against removing the non-Hg metals emission limits from MATS and if our proposal to revise the fPM emission limits was accepted, we would develop non-Hg emission limits by multiplying the revised fPM emission limit by each individual (or total) non-Hg PM ratio identified in the aforementioned *Emission Factor Development for RTR Risk Modeling Dataset for Coal- and Oil-fired EGUs* memorandum.[55] The resulting values would become the individual non-Hg metals emission limits; their sum would become the total non-Hg metals emission limit. We solicit comment on our proposed approach to develop non-Hg metals emission limits in the event that our preferred approach—removing the non-Hg metals emission limits—is not selected. Note that should our proposed approach to remove non-Hg metals emission limits from MATS not be finalized, we would need to adjust the compliance determination method because the current quarterly emissions testing would not be consistent with the continuous monitoring and compliance determination method afforded by acceptance of our proposal to require use of PM CEMS for compliance with the fPM emission limit. At least one CEMS manufacturer offers a multi-metals instrument that would be suitable or could be adjusted to account for appropriate detection levels for ongoing compliance purposes. In addition, were our proposal to remove non-Hg metals from the rule not finalized, very frequent emissions testing, perhaps on the order of weekly, might be able to provide more information on compliance status. While not continuous, as provided by CEMS, such information would be more frequent than provided by the quarterly emissions testing required by the rule. We solicit comment on appropriate means to determine compliance with non-Hg metals emission limits, provided our proposed approach—removal of non-Hg metals emission limits—is not finalized. Please include in your comments information related to the frequency of collected data, the continuity of data supplied by your suggested means of compliance, and initial and ongoing annual costs of your suggested means of compliance.

3. Removing Use of PM CPMS for Compliance Determinations

Use of PM CPMS for compliance purposes appears to be limited to four EGUs at one site in South Carolina, and these EGUs account for less than 0.5 percent of all EGUs in operation. According to submitted reports, each of the EGUs relies on an instrument (Sick Maihak RWE–200) which provides a milliamp signal that is used to develop an ongoing operating limit; this instrument is advertised by its maker to be able to serve as a PM CEMS with little to no modification, meaning that the instrument can provide direct measurement of fPM in terms of the emission standard—pounds per million BTU. Given that PM CPMS use costs more than PM CEMS use, that PM CPMS does not provide continuous values in terms of the emission standard, that PM CPMS is rarely in use among EGUs, and that the existing PM CPMS can be used as PM CEMS, we propose to remove the ability to use PM CPMS for compliance purposes in MATS. The EPA solicits comment on the use of PM CPMS for compliance purposes; to the extent there are other EGU owners or operators using PM CPMS, commenters should identify each EGU, along with its ORIS code and MW nameplate capacity, as well as the PM CPMS manufacturer and model in use. The EPA also solicits comment on the proposal to replace PM CPMS with PM CEMS for compliance use in MATS; when providing comments, please provide detailed costs—including initial instrument cost, installation cost, and operating and maintenance costs—as well as a description of ongoing

[53] See *Emission Factor Development for RTR Risk Modeling Dataset for Coal- and Oil-fired EGUs,* available at *https://www.regulations.gov* at Docket ID No. EPA–HQ–OAR–2018–0794–0010.

[54] Data obtained from the Emissions and Generation Resource Integrated Database (eGRID), available at *https://www.epa.gov/egrid.*

[55] See *https://www.regulations.gov* at Docket ID No. EPA–HQ–OAR–2018–0794–0010.

operating activities from those EGUs with existing PM CPMS used for compliance purposes.

E. What compliance dates are we proposing, and what is the rationale for the proposed compliance dates?

The EPA is proposing to revise the fPM emission limit for existing coal-fired EGUs and the Hg emission limit for lignite-fired EGUs. The EPA is proposing up to 3 years after the effective date for EGUs subject to MATS to meet these new emission limits. However, the EPA solicits comment on whether more than 1 year is needed to comply considering the potential need to upgrade control systems. In addition, the EPA is proposing that affected EGUs demonstrate compliance with the fPM emission limit using PM CEMS, removing the alternative compliance options. Sources must demonstrate that compliance has been achieved, by conducting the required performance tests, and other activities as specified in 40 CFR part 63, subpart UUUUU, including a minimum sampling collection time of 3 hours per run, no later than 3 years after the promulgation date. To demonstrate initial compliance using PM CEMS, the initial performance test consists of 30-boiler operating days. If the PM CEMS is certified prior to the compliance date, the test begins with the first operating day on or after that date. If the PM CEMS is not certified prior to the compliance date, the test begins with the first operating day after certification testing is successfully completed. Continuous compliance with the revised fPM emission limit is required to be demonstrated on a 30-boiler operating day rolling average basis, defined in 40 CFR 63.10021(b), as the arithmetic average emissions rates over the last continuous 30 days provided the boiler was operating. The EPA proposes to remove the use of PM CPMS for compliance determinations and the non-Hg metal emission limits—both individual and total—3 years after the promulgation date. The EPA considers 3 years to be as expedient as can be required considering the potential need to upgrade or replace monitoring systems. The EPA solicits comment on whether 3 years is an appropriate amount of time for EGUs to upgrade or replace monitoring systems, and whether quarterly stack testing should continue to apply for EGUs that have a binding commitment to permanently cease operations in the near term. Additionally, the EPA proposes to remove fPM and the total and individual non-Hg HAP metals from the LEE program no later than 3 years after the promulgation date to align with the proposed compliance method of PM CEMS. Lastly, the EPA is proposing to remove the alternative work practice standard in paragraph (2) of the definition of ''startup.'' The EPA proposes that affected sources must utilize paragraph (1) of the definition of ''startup'' as specified in 40 CFR part 63, subpart UUUUU, no later than 180 days after the effective date.

VI. Summary of Cost, Environmental, and Economic Impacts

In accordance with E.O. 12866 and 13563, the guidelines of OMB Circular A–4, and EPA's Guidelines for Preparing Economic Analyses,[56] the EPA prepared an RIA for this proposal. The RIA analyzes the benefits and costs associated with the projected emissions reductions under the proposed requirements, a less stringent set of requirements, and a more stringent set of requirements to inform the EPA and the public about these projected impacts.

We start this section of the preamble describing how the RIA for this proposed rule structured the proposed and less and more stringent regulatory options in the RIA. The proposed regulatory option in the RIA includes the proposed revision to the fPM standard to 0.010 lb/MMBtu, in which fPM is a surrogate for non-Hg metal HAP, the proposed revision to the Hg standard for lignite-fired EGUs to 1.2 lb/TBtu, the proposal to require PM CEMS to demonstrate compliance, and the removal of the startup definition number two. The more stringent regulatory option examined in the RIA tightens the proposed revision to the fPM standard to 0.006 lb/MMBtu. The other three proposed amendments are not changed in the more stringent regulatory option examined in the RIA. Finally, the less stringent regulatory option examined in the RIA assumed the fPM and Hg limits remain unchanged and examines just the proposed PM CEMS requirement and removal of startup definition number two.

A. What are the affected sources?

The EPA estimates that there are 302 coal- and 56 oil-fired EGUs that will be subject to the MATS rule by the compliance date.

B. What are the air quality impacts?

The EPA estimated emissions reductions under the proposed rule for the years 2028, 2030, and 2035 based upon IPM projections. The EPA also used IPM to estimate emissions reductions for the more stringent regulatory option examined in the RIA. The less stringent regulatory option presented in the RIA has no quantified emissions reductions associated with the proposed requirements for PM CEMS and the removal of startup definition number two that constitute the less stringent regulatory option presented in the RIA.

The emissions reduction estimates presented in the RIA include reductions in pollutants directly targeted by this rule, such as Hg, and changes in other pollutants emitted from the power sector as a result of the compliance actions projected under this proposed rule. Table 10 presents the projected emissions reductions under the proposed rule.

TABLE 10—PROJECTED EGU EMISSIONS IN THE BASELINE AND UNDER THE PROPOSED RULE: 2028, 2030, AND 2035

Year	Emissions reductions		
	Proposed rule	Less stringent regulatory option	More stringent regulatory option
Hg (lbs.)			
2028	62.0	0.0	208.0
2030	67.0	0.0	169.0
2035	82.0	0.0	168.0

[56] U.S. EPA (2014). Guidelines for Preparing Economic Analyses. U.S. EPA. Washington, DC, U.S. Environmental Protection Agency, Office of Policy, National Center for Environmental Economics.

TABLE 10—PROJECTED EGU EMISSIONS IN THE BASELINE AND UNDER THE PROPOSED RULE: 2028, 2030, AND 2035—Continued

Year	Emissions reductions		
	Proposed rule	Less stringent regulatory option	More stringent regulatory option
$PM_{2.5}$ (thousand tons)			
2028	0.4	0.0	2.6
2030	0.4	0.0	1.5
2035	0.8	0.0	1.3
SO_2 (thousand tons)			
2028	0.9	0.0	11.6
2030	0.5	0.0	0.3
2035	1.5	0.0	8.8
Ozone-season NO_X (thousand tons)			
2028	0.2	0.0	7.2
2030	0.4	0.0	5.1
2035	3.2	0.0	5.6
Annual NO_X (thousand tons)			
2028	0.4	0.0	18.1
2030	0.8	0.0	9.5
2035	3.4	0.0	8.7
HCl (thousand tons)			
2028	0.0	0.0	0.2
2030	0.0	0.0	0.1
2035	0.0	0.0	0.1
CO_2 (million metric tons)			
2028	0.2	0.0	21.9
2030	0.8	0.0	8.7
2035	4.6	0.0	2.9

Section 3 of the RIA presents a detailed discussion of the emissions projections under the regulatory options as described in the RIA. Section 3 also describes the compliance actions that are projected to produce the emissions reductions in Table 10. Please see section VI.E of this preamble and section 4 of the RIA for detailed discussions of the projected health, welfare, and climate benefits of these emissions reductions.

C. What are the cost impacts?

The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and policy scenarios. In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the proposed requirements. The compliance cost estimates were developed with EPA's Power Sector Modeling Platform v6 using IPM, a state-of-the-art, peer-reviewed dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. IPM provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting electricity demand and various environmental, transmission, dispatch, and reliability constraints. IPM's least-cost dispatch solution is designed to ensure generation resource adequacy, either by using existing resources or through the construction of new resources. IPM addresses reliable delivery of generation resources for the delivery of electricity between the 78 IPM regions, based on current and planned transmission capacity, by setting limits to the ability to transfer power between regions using the bulk power transmission system. The model includes state-of-the-art estimates of the cost and performance of air pollution control technologies with respect to Hg and other HAP controls.

We estimate the present value (PV) of the projected compliance costs over the 2028 to 2037 period, as well as estimate the equivalent annual value (EAV) of the flow of the compliance costs over this period. All dollars are in 2019 dollars. Consistent with Executive Order 12866 guidance, we estimate the PV and EAV using 3 and 7 percent discount rates. Table 11 presents the estimates of compliance costs across the regulatory options examined in the RIA.

TABLE 11—PROJECTED COMPLIANCE COSTS OF THE PROPOSED RULE, LESS STRINGENT ALTERNATIVE, AND MORE STRINGENT ALTERNATIVE, 2028 THROUGH 2037

[Millions 2019$, discounted to 2023] [a]

	3% Discount rate			7% Discount rate		
	Proposed	Less stringent	More stringent	Proposed	Less stringent	More stringent
Present Value (PV)	330	−45	4,600	230	−31	3,400
Equivalent Annualized Value (EAV)	38	−5.2	540	33	−4.5	490

[a] Values have been rounded to two significant figures.

The PV of the compliance costs for the proposal, discounted at the 3 percent rate, is estimated to be about $330 million, with an EAV of about $38 million. At the 7 percent discount rate, the PV of the compliance costs of the proposal is estimated to be about $230 million, with an EAV of about $33 million. For a detailed description of these compliance cost projections, please see section 3 of the RIA, which is available in the docket for this action.

D. What are the economic impacts?

This proposed action has energy market implications. The power sector analysis supporting this action indicates that there are important power sector impacts that are worth noting, although they are small relative to recent market-driven changes in the sector and compared to some other EPA air regulatory actions for EGUs.

There are several small national changes in energy prices projected to result from the proposed revisions to the MATS rule. Retail electricity prices are projected to increase in the contiguous U.S. by an average of less than 0.1 percent in 2028, 2030, and 2035. In 2035, the delivered natural gas price is anticipated to increase by less than 0.1 percent in response to the proposed rule. There are several other types of energy impacts associated with the proposed revisions to MATS. Some coal-fired capacity, about 500 MW (less than 1 percent of operational coal capacity), is projected to become uneconomic to maintain by 2028. Coal production for use in the power sector is not projected to change significantly by 2028.

The short-term estimates for employment needed to design, construct, and install the control equipment in the 3-year period before the compliance date are also provided using an approach that estimates employment impacts for the environmental protection sector based on projected changes from IPM on the number and scale of pollution controls and labor intensities in relevant sectors. Finally, some of the other types of employment impacts that will be ongoing are estimated using IPM outputs and labor intensities, as reported in section 5 of the RIA.

E. What are the benefits?

Pursuant to E.O. 12866, the RIA for this action analyzes the benefits associated with the projected emissions reductions under this proposal to inform the EPA and the public about these projected impacts. This proposed rule is projected to reduce emissions of Hg and non-Hg metal HAP, $PM_{2.5}$, SO_2, NO_X, and CO_2 nationwide. The potential impacts of these emissions reductions are discussed in detail in section 4 of the RIA.

The projected reductions in Hg emissions should reduce the bioconcentration of methylmercury in fish in nearby waterbodies. Subsistence fishing is associated with vulnerable populations, including minorities and those of low socioeconomic status. Methylmercury exposure to subsistence fishers from lignite-fired units is below the current reference dose (RfD) for methylmercury neurodevelopmental toxicity. The EPA considers exposures at or below the RfD are unlikely to be associated with appreciable risk of deleterious effects across the population. However, no RfD defines an exposure level corresponding to zero risk; moreover, the RfD does not represent a bright line above which individuals are at risk of adverse effects. In addition, there was no evidence of a threshold for methylmercury-related neurotoxicity within the range of exposures in the Faroe Islands study which served as the primary basis for the RfD.[57] Reductions in Hg emissions from lignite-fired facilities should further reduce exposure to methylmercury for subsistence fisher sub-populations located in the vicinity of these facilities. The projected reductions in non-Hg metal HAP may lead to reduced exposure to carcinogenic metal HAP for residential populations near these facilities, which should help the EPA maintain an ample margin of safety. Furthermore, there is the potential for reductions in Hg and non-Hg HAP emissions to enhance ecosystem services and improve ecological outcomes, both of which can have positive economic effects although it is difficult to estimate these benefits and consequently they have not been included in the set of quantified benefits.

The proposed rule is expected to reduce emissions of direct $PM_{2.5}$, NO_X, and SO_2 nationally throughout the year. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects. This proposed rule is also expected to reduce ozone-season NO_X emissions nationally. In the presence of sunlight, NO_X and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X emissions in most locations reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local concentration levels of VOCs.

The health effect endpoints, effect estimates, benefit unit-values, and how they were selected, are described in the TSD titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits,* which is referenced in the RIA for this action. Our approach for updating the endpoints and to identify suitable epidemiologic studies, baseline incidence rates, population demographics, and valuation estimates is summarized in section 4 of the RIA. This proposed rule is projected to reduce $PM_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $1.9 billion, with an EAV of about $220 million discounted at 3 percent.

Because of projected changes in dispatch under the proposed requirements, the proposed rule is also projected to reduce CO_2 emissions. The EPA estimated the climate benefits from

[57] U.S. EPA. 2001. IRIS Summary for Methylmercury. U.S. Environmental Protection Agency, Washington, DC. (USEPA, 2001).

this proposed rule using estimates of the social cost of greenhouse gases (SC–GHG), specifically the social cost of carbon (SC–CO_2). The SC–CO_2 is the monetary value of the net harm to society associated with a marginal increase in CO_2 emissions in a given year, or the benefit of avoiding that increase. In principle, SC–CO_2 includes the value of all climate change impacts (both negative and positive), including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC–CO_2, therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO_2 emissions. In practice, data and modeling limitations naturally restrain the ability of SC–CO_2 estimates to include all the important physical, ecological, and economic impacts of climate change, such that the estimates are a partial accounting of climate change impacts and will therefore, tend to be underestimates of the marginal benefits of abatement. The EPA and other Federal agencies began regularly incorporating SC–GHG estimates in their benefit-cost analyses conducted under E.O. 12866 [58] since 2008, following a Ninth Circuit Court of Appeals remand of a rule for failing to monetize the benefits of reducing CO_2 emissions in a rulemaking process.

We estimate the global social benefits of CO_2 emission reductions expected from the proposed rule using the SC–GHG estimates presented in the February 2021 TSD: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under E.O. 13990. These SC–GHG estimates are interim values developed under E.O. 13990 for use in benefit-cost analyses until updated estimates of the impacts of climate change can be developed based on the best available climate science and economics. We have evaluated the SC–GHG estimates in the TSD and have determined that these estimates are appropriate for use in estimating the global social benefits of CO_2 emission reductions expected from this proposed rule. After considering the TSD, and the issues and studies discussed therein, the EPA finds that these estimates, while likely an underestimate, are the best currently available SC–GHG estimates. These SC–GHG estimates were developed over many years using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. As discussed in section 4.4 of the RIA, these interim SC–CO_2 estimates have a number of limitations, including that the models used to produce them do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate-change literature and that several modeling input assumptions are outdated. As discussed in the February 2021 TSD, the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) finds that, taken together, the limitations suggest that these SC–CO_2 estimates likely underestimate the damages from CO_2 emissions. The IWG is currently working on a comprehensive update of the SC–GHG estimates (under E.O. 13990) taking into consideration recommendations from the National Academies of Sciences, Engineering and Medicine, recent scientific literature, public comments received on the February 2021 TSD and other input from experts and diverse stakeholder groups. The EPA is participating in the IWG's work. In addition, while that process continues, the EPA is continuously reviewing developments in the scientific literature on the SC–GHG, including more robust methodologies for estimating damages from emissions, and looking for opportunities to further improve SC–GHG estimation going forward. Most recently, the EPA has developed a draft updated SC–GHG methodology within a sensitivity analysis in the RIA of the EPA's November 2022 supplemental proposal for oil and gas standards that is currently undergoing external peer review and a public comment process. See section 4.4 of the RIA for more discussion of this effort.

Table 12 presents the estimated PV and EAV of the projected health and climate benefits across the regulatory options examined in the RIA in 2019 dollars discounted to 2023. The table includes benefit estimates for the less and more stringent regulatory options examined in the RIA for this proposal.

TABLE 12—PROJECTED BENEFITS OF THE PROPOSED RULE, LESS STRINGENT ALTERNATIVE, AND MORE STRINGENT ALTERNATIVE, 2028 THROUGH 2037

[Millions 2019$, discounted to 2023] [a]

	Present value (PV)					
	3% Discount rate			7% Discount rate [d]		
	Proposed	Less stringent	More stringent	Proposed	Less stringent	More stringent
Health Benefits [c]	1,900	0.0	11,000	1,200	0.0	7,100
Climate Benefits [d]	1,400	0.0	3,200	[d] 1,400	[d] 0.0	[d] 3,200
Benefits [e]	3,300	0.0	14,000	2,600	0.0	10,000
	Equal annualized value (EAV) [b]					
	3% Discount rate			7% Discount rate [d]		
	Proposed	Less stringent	More stringent	Proposed	Less stringent	More stringent
Health Benefits [c]	220	0.0	1,300	170	0.0	1,000
Climate Benefits [d]	170	0.0	380	[d] 170	[d] 0.0	[d] 380

[58] Benefit-cost analyses have been an integral part of executive branch rulemaking for decades. Presidents since the 1970s have issued executive orders requiring agencies to conduct analysis of the economic consequences of regulations as part of the rulemaking development process. E.O. 12866, released in 1993 and still in effect today, requires that for all economically significant regulatory actions, an agency provide an assessment of the potential costs and benefits of the regulatory action, and that this assessment include a quantification of benefits and costs to the extent feasible.

	Equal annualized value (EAV) [b]					
	3% Discount rate			7% Discount rate [d]		
	Proposed	Less stringent	More stringent	Proposed	Less stringent	More stringent
Benefits [e]	390	0.0	1,700	330	0.0	1,400

[a] Values have been rounded to two significant figures. Rows may not appear to sum correctly due to rounding.
[b] The EAV of benefits are calculated over the 10-year period from 2028 to 2037.
[c] The projected monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent.
[d] Climate benefits are based on reductions in CO_2 emissions and are calculated using four different estimates of the social cost of carbon dioxide (SC–CO_2): model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate. For the presentational purposes of this table, we show the climate benefits associated with the average SC–CO_2 at a 3 percent discount rate, but the Agency does not have a single central SC–CO_2 point estimate. Climate benefits in this table are discounted using a 3 percent discount rate to obtain the PV and EAV estimates in the table. We emphasize the importance and value of considering the benefits calculated using all four SC–CO_2 estimates. Section 4.4 of the RIA presents estimates of the projected climate benefits of this proposal using all four rates. We note that consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is warranted when discounting intergenerational impacts.
[e] Several categories of benefits remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table. Non-monetized benefits include benefits from reductions in Hg and non-Hg metal HAP emissions and from the increased transparency and accelerated identification of anomalous emission anticipated from requiring CEMS.

This proposed rule is projected to reduce $PM_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $1.9 billion, with an EAV of about $220 million discounted at 3 percent. The projected PV of monetized climate benefits of the proposal are estimated to be about $1.4 billion, with an EAV of about $170 million using the SC–CO_2 discounted at 3 percent. Thus, this proposed rule would generate a PV of monetized benefits of $3.3 billion, with an EAV of $390 million discounted at a 3 percent rate.

At a 7 percent discount rate, this proposed rule is expected to generate projected PV of monetized health benefits of $1.2 billion, with an EAV of about $170 million discounted at 7 percent. Climate benefits remain discounted at 3 percent in this benefits analysis and are estimated to be about $1.4 billion, with an EAV of about $170 million using the SC–CO_2. Thus, this proposed rule would generate a PV of monetized benefits of $2.6 billion, with an EAV of $330 million discounted at a 7 percent rate. The potential benefits from reducing Hg and non-Hg metal HAP were not monetized and are therefore not directly reflected in the monetized benefit-cost estimates associated with this proposal. Potential benefits from the increased transparency and accelerated identification of anomalous emission anticipated from requiring CEMS were also not monetized in this analysis and are therefore also not directly reflected in the monetized benefit-cost comparisons. We nonetheless consider these impacts in our evaluation of the net benefits of the rule and find, if we were able to monetize these beneficial impacts, the proposal would have greater net benefits than shown in Table 12.

F. What analysis of environmental justice did we conduct?

Executive Order 12898 directs the EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms; specifically, minority populations, low-income populations, and Indigenous peoples.[59] Additionally, Executive Order 13985 is intended to advance racial equity and support underserved communities through federal government actions.[60] The EPA defines environmental justice (EJ) as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA further defines the term fair treatment to mean that ''no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies.'' [61] In recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

The EPA's EJ technical guidance [62] states that ''[t]he analysis of potential EJ concerns for regulatory actions should address three questions:

1. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?

2. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?

3. For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?''

To address these questions in the EPA's first quantitative EJ analysis in the context of a MATS rule, the EPA developed a unique analytical approach that considers the purpose and specifics of the proposed rulemaking, as well as the nature of known and potential disproportionate and adverse exposures and impacts. However, due to data limitations, it is possible that our analysis failed to identify disparities that may exist, such as potential EJ characteristics (*e.g.,* residence of historically red lined areas), environmental impacts (*e.g.,* other ozone metrics), and more granular spatial resolutions (*e.g.,* neighborhood scale) that were not evaluated. Also due to data and resource limitations, we discuss HAP and climate EJ impacts of this action qualitatively (sections 6.3 and 6.6 of the RIA).

For this proposed rule, we employ two types of analysis to respond to the previous three questions: proximity analyses and exposure analyses. Both types of analyses can inform whether there are potential EJ concerns for population groups of concern in the

[59] 59 FR 7629, February 16, 1994.
[60] 86 FR 7009, January 20, 2021.
[61] *https://www.epa.gov/environmentaljustice.*
[62] U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions.

baseline (question 1).[63] In contrast, only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns after implementation of the regulatory options under consideration (question 2) and whether potential EJ concerns will be created or mitigated compared to the baseline (question 3). While the exposure analysis can respond to all three questions, several caveats should be noted. For example, the air pollutant exposure metrics are limited to those used in the benefits assessment. For ozone, that is the maximum daily 8-hour average, averaged across the April through September warm season (AS–MO3) and for $PM_{2.5}$ that is the annual average. This ozone metric likely smooths potential daily ozone gradients and is not directly relatable to the NAAQS, whereas the $PM_{2.5}$ metric is more similar to the long term $PM_{2.5}$ standard. The air quality modeling estimates are also based on state level emission data paired with facility-level baseline emissions and provided at a resolution of 12 km^2. Additionally, here we focus on air quality changes due to this proposed rulemaking and infer post-policy exposure burden impacts.

Exposure analysis results are provided in two formats: aggregated and distributional. The aggregated results provide an overview of potential ozone exposure differences across populations at the national- and state-levels, while the distributional results show detailed information about ozone concentration changes experienced by everyone within each population.

In section 6 of the RIA we utilize the two types of analysis to address the three EJ questions by quantitatively evaluating: (1) the proximity of affected facilities to populations of potential EJ concern (section 6.4); and (2) the potential for disproportionate ozone and $PM_{2.5}$ concentrations in the baseline and concentration changes after rule implementation across different demographic groups (section 6.5). Each of these analyses depends on mutually exclusive assumptions, was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses can be relevant for identifying populations that may be exposed to local environmental stressors, such as local NO_2 and SO_2 emitted from affected sources in this proposed rule, traffic, or noise. The baseline analysis indicates that on average the populations living within 10 km of coal plants potentially subject to the proposed or alternate filterable PM standards have a higher percentage of people living below two times the poverty level than the national average. In addition, on average the percentage of the Native American population living within 10 km of lignite plants potentially subject to proposed Hg standard is higher than the national average. Relating these results to EJ question 1, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (*e.g.,* SO_2) for certain population groups of concern in the baseline (question 1). However, as proximity to affected facilities does not capture variation in baseline exposure across communities, nor does it indicate that any exposures or impacts will occur, these results should not be interpreted as a direct measure of exposure or impact.

As HAP exposure results generated as part of the 2020 Residual Risk analysis were below both the presumptive acceptable cancer risk threshold and noncancer health benchmarks and this proposed regulation should further reduce exposure to HAP, there are no 'disproportionate and adverse effects' of potential EJ concern. Therefore, we did not perform a quantitative EJ assessment of HAP risk.

This proposed rule is also expected to reduce emissions of direct $PM_{2.5}$, NO_X, and SO_2 nationally throughout the year. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$ and NO_X is a precursor to ozone formation, reducing these emissions would impact human exposure. Quantitative ozone and $PM_{2.5}$ exposure analyses can provide insight into all three EJ questions, so they are performed to evaluate potential disproportionate impacts of this rulemaking. Even though both the proximity and exposure analyses can potentially improve understanding of baseline EJ concerns (question 1), the two should not be directly compared. This is because the demographic proximity analysis does not include air quality information and is based on current, not future, population information.

The baseline analysis of ozone and $PM_{2.5}$ concentration burden responds to question 1 from EPA's EJ Technical Guidance document more directly than the proximity analyses, as it evaluates a form of the environmental stressor targeted by the regulatory action. Baseline ozone and $PM_{2.5}$ analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, those less educated, and children may experience somewhat higher ozone and $PM_{2.5}$ concentrations compared to the national average. Therefore, also in response to question 1, there likely are potential EJ concerns associated with ozone and $PM_{2.5}$ exposures affected by the regulatory action for population groups of concern in the baseline. However, these baseline exposure results have not been fully explored and additional analyses are likely needed to understand potential implications. Due to the small magnitude of the exposure changes across population demographics associated with the rulemaking relative to the magnitude of the baseline disparities, we infer that post-policy EJ ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action or alternative under consideration (question 2).

Question 3 asks whether potential EJ concerns will be created or mitigated as compared to the baseline. Due to the very small magnitude of differences across demographic population post-policy ozone and $PM_{2.5}$ exposure impacts, we do not find evidence that potential EJ concerns related to ozone and $PM_{2.5}$ concentrations will be created or mitigated as compared to the baseline.[64]

Prior to this proposed rule, the EPA initiated a public outreach effort to gather input from stakeholder groups likely to be interested in this proposed rule. Specifically, the EPA presented on a National EJ call on September 20, 2022, to share information about the proposed rule and solicit feedback about potential EJ considerations. The webinar was attended by individuals representing state governments, federally recognized tribes, environmental non-governmental organizations, higher education institutions, industry, and the EPA.[65]

[63] The baseline for proximity analyses is current population information, whereas the baseline for ozone exposure analyses are the future years in which the regulatory options will be implemented (*e.g.,* 2023 and 2026).

[64] Please note, exposure results should not be extrapolated to other air pollutant. Detailed EJ analytical results can be found in Section 6 of the RIA.

[65] This does not constitute the EPA's tribal consultation under E.O. 13175, which is described in section VIII.F of this proposed rule.

In addition to the engagement conducted prior to this proposed rule, the EPA is providing the public, including those communities disproportionately impacted by the burdens of pollution, opportunities to engage in the EPA's public comment period for this proposed rule, including by hosting a public hearing. This public hearing will occur according to the schedule identified in the **SUPPLEMENTARY INFORMATION** under the heading entitled *Participation in virtual public hearing* of this proposed rule.

VII. Request for Comments

We solicit comments on this proposed action. In addition to general comments on this proposed action, we are also interested in additional data that may improve the analyses. We are specifically interested in receiving any information regarding developments in practices, processes, and control technologies that reduce HAP emissions. We are also interested in comments on any reliance interests stakeholders may have that would be affected by this proposed action.

VIII. Statutory and Executive Order Reviews

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

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

This action was submitted to the OMB for review under section 3(f)(1) of Executive Order 12866. Any changes made in response to recommendations received as part of review under Executive Order 12866 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 Proposed 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–23–002), is available in the docket and is briefly summarized in section VI of this preamble and here.

Table 13 presents the estimated PV and EAV of the projected health benefits, climate benefits, compliance costs, and net benefits of the proposed rule in 2019 dollars discounted to 2023. The estimated monetized net benefits are the projected monetized benefits minus the projected monetized costs of the proposed rule. Table 13 also presents results for the less stringent and more stringent alternatives that are examined in the RIA for this proposal.

Under E.O. 12866, the EPA is directed to consider all of the costs and benefits of its actions, not just those that stem from the regulated pollutant. Accordingly, the projected monetized benefits of the proposal include health benefits associated with projected reductions in fine particulate matter ($PM_{2.5}$) and ozone concentration. The projected monetized benefits also include climate benefits due to reductions in CO_2 emissions. The projected health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. The projected climate benefits in this table are based on estimates of the SC–CO_2 at a 3 percent discount rate and are discounted using a 3 percent discount rate to obtain the PV and EAV estimates in the table. The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and policy scenarios. In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the proposed requirements and represent the EPA's best estimate of the social cost of the proposed rulemaking.

TABLE 13—PROJECTED MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE PROPOSED RULE, LESS STRINGENT ALTERNATIVE, AND MORE STRINGENT ALTERNATIVE, 2028 THROUGH 2037

[Millions 2019$, discounted to 2023] [a]

	Present value (PV)					
	3% Discount rate			7% Discount rate [d]		
	Proposed	Less stringent	More stringent	Proposed	Less stringent	More stringent
Health Benefits [c]	1,900	0.0	11,000	1,200	0.0	7,100
Climate Benefits [d]	1,400	0.0	3,200	[d] 1,400	[d] 0.0	[d] 3,200
Compliance Costs	330	−45	4,600	230	−31	3,400
Net Benefits [e]	3,000	45	9,800	2,400	31	6,900
	Equal Annualized Value (EAV) [b]					
	3% Discount rate			7% Discount rate [d]		
	Proposed	Less stringent	More stringent	Proposed	Less stringent	More stringent
Health Benefits [c]	220	0.0	1,300	170	0.0	1,000
Climate Benefits [d]	170	0.0	380	[d] 170	[d] 0.0	[d] 380
Compliance Costs	38	−5.2	540	33	−4.5	490
Net Benefits [e]	350	5.2	1,100	300	4.5	900

[a] Values have been rounded to two significant figures. Rows may not appear to sum correctly due to rounding.

[b] The EAV of costs and benefits are calculated over the 10-year period from 2028 to 2037.

[c] The projected monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent.

[d] Climate benefits are based on reductions in CO_2 emissions and are calculated using four different estimates of the social cost of carbon dioxide (SC–CO_2): model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate. For the presentational purposes of this table, we show the climate benefits associated with the average SC–CO_2 at a 3 percent discount rate, but the Agency does not have a single central SC–CO_2 point estimate. Climate benefits in this table are discounted using a 3 percent discount rate to obtain the PV and EAV estimates in the table. We emphasize the importance and value of considering the benefits calculated using all four SC–CO_2 estimates. Section 4.4 of the RIA presents estimates of the projected climate benefits of this proposal using all four rates. We note that consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is warranted when discounting intergenerational impacts.

[e] Several categories of benefits remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table. Non-monetized benefits include benefits from reductions in Hg and non-Hg metal HAP emissions and from the increased transparency and accelerated identification of anomalous emission anticipated from requiring CEMS.

As shown in Table 13, this proposed rule is projected to reduce $PM_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $1.9 billion, with an EAV of about $220 million discounted at 3 percent. The proposed rule is also projected to reduce greenhouse gas emissions in the form of CO_2, producing a projected PV of monetized climate benefits of about $1.4 billion, with an EAV of about $170 million using the SC–CO_2 discounted at 3 percent. The PV of the projected compliance costs are $330 million, with an EAV of about $38 million discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of $3 billion and EAV of $350 million.

At a 7 percent discount rate, this proposed rule is expected to generate projected PV of monetized health benefits of $1.2 billion, with an EAV of about $170 million. Climate benefits remain discounted at 3 percent in this net benefits analysis. Thus, this proposed rule would generate a PV of monetized benefits of $2.6 billion, with an EAV of $340 million discounted at a 7 percent rate. The PV of the projected compliance costs are $230 million, with an EAV of $33 million discounted at 7 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of $2.4 billion and an EAV of $300 million.

The potential benefits from reducing Hg and non-Hg metal HAP were not monetized and are therefore not directly reflected in the monetized benefit-cost estimates associated with this proposal. Potential benefits from the increased transparency and accelerated identification of anomalous emission anticipated from requiring CEMS requiring were also not monetized in this analysis and are therefore also not directly reflected in the monetized benefit-cost comparisons. We nonetheless consider these impacts in our evaluation of the net benefits of the rule and find, if we were able to monetize these beneficial impacts, the proposal would have greater net benefits than shown in Table 13.

B. Paperwork Reduction Act (PRA)

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 proposed rule, which are a revision to the existing approved information collection activities, have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2137–12. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

The information collection activities in this proposed rule include continuous emission monitoring, performance testing, 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).

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: 187 per year.

Frequency of response: The frequency of responses varies depending on the burden item. Responses include daily calibrations, quarterly inspections, and semiannual compliance reports.

Total estimated burden: 443,000 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $100,100,000 (per year), includes $49,600,000 annualized capital or 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.

Submit your comments on the EPA's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *https://www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under Review—Open for Public Comments'' or by using the search function. OMB must receive comments no later than June 23, 2023.

C. Regulatory Flexibility Act (RFA)

The EPA certifies that this proposed action will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (RFA). The EPA chose to examine the projected impacts of a more stringent regulatory option than proposed on small entities in order to present a scenario of ''maximum cost impact.'' As projected cost impacts of the proposed rule is dominated by cost impacts of the more stringent alternative also examined in the RIA, a no SISNOSE conclusion for the more stringent option can be extended to the proposed rule and less stringent option.

In 2028, the EPA identified 26 potentially affected small entities operating 41 units at 27 facilities, and of these 26, only two small entities may experience compliance cost increases greater than 1 percent of revenue under the proposed rule, and three small entities may experience such increases under the more stringent alternative.

Details of this analysis are presented in section 5 of the RIA, which is in the public docket.

D. Unfunded Mandates Reform Act of 1995 (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local, or tribal governments or the private sector. In light of the interest in this rule among governmental entities, the EPA initiated consultation with governmental entities. The EPA invited the following 10 national organizations representing state and local elected officials to a virtual meeting on September 22, 2022: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations representing elected state and local officials have been identified by the EPA as the ''Big 10'' organizations appropriate to contact for purpose of consultation with elected officials. Also, the EPA invited air and utility professional groups who may have state and local government members, such as the Association of Air Pollution Control Agencies, National Association of Clean Air Agencies, and others to participate in the meeting. The purpose of the consultation was to provide general background on the review of the MATS RTR, answer questions, and solicit input from state and local governments. Subsequent to the September 22, 2022, meeting, the EPA received a letter from the American Public Power Association (APPA). The EPA opened a non-rulemaking docket for public input on the EPA's efforts to reduce greenhouse gas emissions from new and existing fossil fuel-fired EGUs. The APPA letter was submitted to the non-rulemaking docket. See Docket ID No. EPA–HQ–OAR–2022–0723–0016. In that letter, APPA stated that they were not able to identify any new cost-effective technologies to reduce HAP emissions and that many of the current technologies used are state-of-the-art controls that continue to reduce HAP emissions. In addition, APPA stated there have been no developments in the emission control practices or processes available to control HAP emissions during startup and shutdown periods. Also, APPA stated that they support the continuation of the 30-day rolling average to assure compliance with MATS emission requirements to allow for hourly variability caused by unit operation and load requirements, including startup and shutdown events.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government.

The EPA believes, however, that this action may be of interest to state and/or local governments. Consistent with the EPA's policy to promote communication between the EPA and state and local governments, the EPA consulted with representatives of state and local governments in the process of developing the proposed amendments to permit them to have meaningful and timely input into its development. The EPA's consultation regarded planned actions for the review of the MATS RTR. The EPA met with 10 national organizations representing state and local elected officials to provide general background on the review of the MATS RTR, answer questions, and solicit input from state and local governments. The UMRA discussion in this preamble includes a description of the consultation. In the spirit of E.O. 13132, and consistent with EPA policy to promote communications between state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

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

This action does not have tribal implications as specified in Executive Order 13175. The Executive order defines tribal implications as ''actions that have substantial direct effects on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes.'' The amendments proposed in this action would not have a substantial direct effect on one or more tribes, change the relationship between the Federal Government and tribes, or affect the distribution of power and responsibilities between the Federal Government and Indian tribes. Thus, Executive Order 13175 does not apply to this action.

Although this action does not have tribal implications as specified in Executive Order 13175, the EPA consulted with tribal officials during the development of this action. On September 1, 2022, the EPA sent a letter to all federally recognized Indian tribes initiating consultation to obtain input on this proposal. The EPA did not receive any requests from consultation from Indian tribes. The EPA also participated in the September 2022 National Tribal Air Association EPA Air Policy Update Call to solicit input on this proposed action.

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

This proposed rule is a ''[c]overed regulatory action'' under Executive Order 13045 because it is a significant regulatory action as described in section 3(f)(1) of Executive Order 12866, and the EPA believes that, even though the residual risk assessment showed all modeled exposures to HAP to be below thresholds for public health concern, the rule should reduce HAP exposure by reducing emissions of Hg and non-Hg HAP with the potential to reduce HAP exposure to vulnerable populations including children. Accordingly, we have evaluated the potential for environmental health or safety effects from exposure to HAP on children. The results of this evaluation are contained in the RIA and are available in the docket for this action. The EPA believes that the $PM_{2.5}$-related, ozone-related, and CO_2-related benefits projected under this proposed rule will further improve children's health. Specifically, the $PM_{2.5}$ and ozone EJ exposure analyses in section 6 of the RIA suggests that nationally, children (ages 0–17) will experience at least as great a reduction in annual $PM_{2.5}$ and ozone exposures as adults (ages 18–64) will experience in 2028, 2030 and 2035 under all regulatory alternatives of this rulemaking.

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

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. For 2028, the compliance year for the proposed standards, the EPA projects a less than 0.1 percent change in retail electricity prices on average across the contiguous U.S., a less than 0.1 percent reduction in coal-fired electricity generation, and a less than 0.1 percent increase in natural gas-fired electricity generation. The EPA does not project a significant change in utility power sector delivered natural gas prices in 2028. Details of the projected energy effects are presented in section 3 of the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

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

Executive Order 12898 (59 FR 7629, February 16, 1994) directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations (people of color and/or Indigenous peoples) and low-income populations.

HAP risks were below both the presumptive acceptable cancer risk threshold and the RfD, and this proposed regulation will likely further reduce exposure to HAP. As such, the EPA believes that this action does not result in disproportionate and adverse effects on people of color, low-income populations, and/or Indigenous peoples.

The EPA believes that $PM_{2.5}$ and ozone exposures that exist prior to this action result in disproportionate and adverse human health or environmental effects on people of color, low-income populations and/or Indigenous peoples. Specifically, baseline $PM_{2.5}$ and ozone and exposure analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, those less educated, and children may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. The EPA believes that this action is not likely to change existing disproportionate $PM_{2.5}$ and ozone exposure impacts on people of color, low-income populations and/or Indigenous peoples. American Indians may also experience disproportionately higher ozone concentrations than the reference group. We do not find evidence that potential EJ concerns related to ozone or $PM_{2.5}$ exposures will be meaningfully exacerbated or mitigated in the regulatory alternatives under consideration as compared to the baseline due to the small magnitude of ozone and $PM_{2.5}$ concentration changes associated with this rule relative to baseline disparities and the very small differences in the distributional analyses of post-policy ozone and $PM_{2.5}$ exposure impacts. Importantly, the action described in this rule is expected to lower ozone and $PM_{2.5}$ in certain areas, and thus mitigate some pre-existing health risks across all populations evaluated.

The documentation for these analyses is contained in section VI.F of this this proposed rule and in section 6, *Environmental Justice Impacts* of the RIA, which is in the public docket.

List of Subjects in 40 CFR Part 63

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

Michael S. Regan,

Administrator.

[FR Doc. 2023–07383 Filed 4–21–23; 8:45 am]

BILLING CODE 6560–50–P